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CUSTOMER CREDIT ACCOUNT RESEARCH AND ANALYSIS SUPPORTING THE CALIFORNIA ENERGY COMMISSION'S RENEWABLE ENERGY PROGRAM PREPARATION OF THE CUSTOMER CREDIT ACCOUNT REPORT FOR THE LEGISLATURE

CONSULTANT'S REPORT

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Customer Credit Account Research and Analysis Supporting the California Energy Commission's Renewable Energy Program Preparation of the Customer Credit Account Report for the Legislature

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Executive Summary

Introduction and Background

The purpose of the California Energy Commission's Customer Credit Account has been to support customer demand for renewable energy, above and beyond that created or supported by other Accounts, with the ultimate goal being to create a self-sustaining, customer-driven market for renewable energy. Two events have changed the context within which this Account operates: the CPUC suspended direct access in September of 2001; and in September, 2002, the Governor signed SB 1078, legislation establishing the California Renewables Portfolio Standard Program (RPS) and providing a target floor for renewable power sales in California.

The questions before the Commission are whether the Customer Credit Account can still serve its purpose in its current form, if it would better serve its purpose with adjustments, or whether it should be discontinued and the funds used for other purposes. The California State Legislature, in SB 1038, specifically requires the following:

Sec. 383.5 (f)(2)(E) of the Public Utilities Code:

> By March 31, 2003, the Energy Commission shall report to the Governor and the Legislature on how to most effectively utilize the funds for customer credits, including whether, and under what conditions, the program should be continued. The report shall include an examination of trends in markets for renewable energy, including the trading of nonenergy attributes, and the role of customer credits in these markets. The report will recommend an appropriate funding allocation for the customer credits and how implementation of the customer credits should be structured, if appropriate.

Summary of Findings

During the first four years of the Renewable Energy Program, customers large and small bought green power supported by Customer Credit Subaccount[1] funds. The Subaccount was successful enough to drive customers towards purchases of renewable power, and to require a 33% reduction in the credit level from 1.5 to 1 ¢/kWh.

Due to the recently added legislative restrictions on the use of the Customer Credit Account funds, without changes to the program, growth of demand for the funds is unlikely in the next two years.[2] However, if legislative restrictions are relaxed on customer and product eligibility for Customer Credit Account funds, growth in demand for funds is likely.

Today, the credit level set for the Customer Credit Account awards is equal to the payment cap from the Existing Account. The relative effectiveness of funds awarded by the Customer Credit or Existing Accounts compared to funds awarded from the New Account[3] is unknown since RPS program design is only now underway. Should the CEC wish to support customer-driven renewable energy demand using Customer Credit Account funds it would have the option of lowering the credit level.

If changes in customer or product eligibility rules are made, the Commission might also consider changing the renewable energy vintage requirements to ensure that a minimum percentage of renewable demand is directed towards renewable energy plants built or repowered after a specific date. This change would ensure that the net renewable energy mix procured by Californians would increase as a result of Customer Credit Account funding.

Customer Credit Account funds could be used to expand renewable energy purchases beyond the goals set by the California RPS, but this will not occur without legislative and program rule changes. If demand for funds does not grow, the remaining Customer Credit Account funds can be reallocated to another Account as needed. Since fund disbursement from the New Account will grow gradually, and over half of the total Renewable Energy Program funds collected annually go to that account, the New Account is not expected to need additional funds in the near term.[4] That fact leaves the CEC with the option of testing changes in the Customer Credit Account and allocating any excess funds from the Customer Credit Account to the New or Emerging Accounts at a later time. This report discusses several options for the redirection of Customer Credit Account funds.

Report Scope

In support of the development of the CEC's report to the Legislature on the Customer Credit Account, the XENERGY team was asked to provide research and analysis in two specific areas:

California's Direct Access Market: Because the suspension of direct access directly impacts the Customer Credit Account, the XENERGY team examined recent events affecting the drivers of direct assess in the state. This section of the report reviews the outcome of recent regulatory events and addresses how ongoing proceedings could affect direct access and demand for Customer Credit Account funds. This section also reviews how relaxing customer and product eligibility rules, within the current direct access market, could change demand for Customer Credit Account funds. One option which would require both legislative and regulatory changes would be to offer RECs or green power through utilities as an add-on option for bundled customers. Such options are now offered through programs in Oregon and New York which we profile in detail in Appendix C.

U.S. Renewable Energy Certificates Markets: The XENERGY team reviewed the commercial success and certification and verification infrastructure for renewable energy certificates (RECs) markets in the U.S. This section of the report includes a survey of wholesale and retail RECs markets in the U.S. and provides insight into how RECs retailers would respond if RECs were made eligible for Customer Credit Account funds. In addition, because a credible retail RECs market is predicated on a solid wholesale RECs infrastructure, we provide additional information about the formal RECs verification systems established in Texas and New England in Appendix A. Because RECs verification across market areas requires coordination between registries, in Appendix B we also include a discussion of current effort to establish a national RECs infrastructure — the American Association of Issuing Bodies (AAIB) — to allow a liquid, easily verifiable wholesale RECs trading market to grow.

Section 1. California's Direct Access Market

Introduction and Background

SB 1038 allocates 10% of the funds collected for the Renewable Energy Program to the Customer Credit Account, supporting customer-driven demand for renewable energy. The Customer Credit Account is intended to layer support of new and existing renewable energy generation in California on top of the support from the Existing and New Accounts. During the first four years of the Renewable Energy Program, the popularity of the customer credit program caused the Energy Commission to reduce the customer credit level by a third, from the legislated cap of 1.5 c/kWh to 1 c/kWh. SB 1038 limits Customer Credit Account eligibility to customers who had contracted for direct access on or before September 20, 2001, the date direct access was suspended by the CPUC.

During 2002, the Customer Credit Account received requests for funds of roughly $5 million, or about 35% of the annual allocation to the Account of $13.5 million. Existing direct access customers represent about 14% of load in the state served by the investor owned utilities, but the vast majority of this load is ineligible for Customer Credit Account funds due to the limits on total funding to large commercial and industrial customers. Demand on the Account could increase substantially, despite the suspension of direct access contracting, if limits on large customer access to the Customer Credit Account were adjusted or removed. In fact, even with the existing limits per customer limits on the non-residential, non-small commercial customers, given the size of direct access load that meets the contracting deadline in statute, the total annual demand on the Customer Credit Account could exceed the 10% Account allocation set by SB 1038 if the total funding restriction for this customer class were removed.[5]

With the change in the market structure in California, suspension of direct access, and the advent of the California Renewables Portfolio Standard (RPS) Program, the legislature has asked for a reevaluation of the customer credit program. The questions that arise are whether the Customer Credit Account can still serve its purpose in its current form, if it would better serve its purpose with adjustments, or whether it should be discontinued and the funds used for other purposes.

Section 383.5 (f)(2)(E) of the Public Utilities Code:

> By March 31, 2003, the Energy Commission shall report to the Governor and the Legislature on how to most effectively utilize the funds for customer credits, including whether, and under what conditions, the program should be continued. The report shall include an examination of trends in markets for renewable energy, including the trading of nonenergy attributes, and the role of customer credits in these markets. The report will recommend an appropriate funding allocation for the customer credits and how implementation of the customer credits should be structured, if appropriate.

We begin evaluation of the effective uses of Renewable Energy Program funds by looking at the status and drivers of the direct access market in California to assess the range of demand for Customer Credit Account funds given the existing set of direct access customers and the rules that govern them. We then turn to potential adjustments in eligibility for the Customer Credit Account and the impact of those changes on demand for the Account funds. The adjustments considered take into account the national trends in the retail, customer-driven renewable energy marketplace. Finally, we consider the other demands on funds for the Renewable Energy Program and where these funds might be used if the Customer Credit Account were discontinued.

Direct Access Market Status

ABX1-1, which became effective February 1, 2001, required the CPUC to suspend direct access but granted the commission discretion as to when the suspension would occur.

Section 80110 of the Water Code:

> After the passage of such period of time after the effective date of this section as shall be determined by the commission, the right of retail end use customers pursuant to Article 6 (commencing with Section 360) of Chapter 2.3 of Part 1 of Division 1 of the Public Utilities Code to acquire service from other providers shall be suspended until the department no longer supplies power hereunder.

The law identified an end point for direct access suspension indicating that the legislature intended to allow direct access contracting to eventually resume.

The CPUC exercised their authority by suspending customers' right to enter into new direct access contracts as of September 20, 2001 by interim order D.01-09-060 and left open the possibility of ordering an earlier suspension date. On March 21, 2002, the CPUC issued D.02-03-055, confirming that the date of suspension would remain September 20, 2001. The March decision discussed the potential application of an exit fee or direct access surcharge for customers who entered direct access contracts prior to the suspension date but set aside the specific determination of such a fee to a later date. In D.02-03-055, the CPUC also set forth some of the key rules for the direct access suspension standstill policy: direct access contract assignments and renewals are allowed, as are customer moves, but add-ons of new load under existing contracts are not.

The CPUC has taken action on several other items that affect direct access customers. A series of decisions were rendered in late 2002 that affect the level of direct access customer surcharges, including:

- D.02-07-032 SCE's Historical Procurement Charge Interim Decision
- D.02-11-074 (replacing D.02-10-063) DWR Bond Surcharge Calculation Methodology Decision
- D.02-11-022 Direct Access Cost Responsibility Surcharge (Exit Fee) Decision

The Exit Fee Decision established a rate cap for direct access customers inclusive of all charges, including SCE's Historical Procurement Charge and the Bond Surcharge. Initially, that cap has been set at 2.7 c/kWh. The commission expects to reevaluate the level of the cap by July 1, 2003.

Consistent with the statutory intent that contracting for direct access be suspended rather than undermine customer choices made prior to suspension, the CPUC has consistently expressed its view that the direct access market should be maintained and remain viable. Examples of the CPUC's support for retaining a viable direct access market follow:

D.02-03-055 p.16

> We agree with ORA and CMTA/CLECA that there are significant risks associated with an earlier suspension date as well as benefits associated with retaining a viable direct access market.

D.02-11-022 p. 109

> We observed that the "pancaking" of surcharges in different proceedings may lead to DA contracts becoming uneconomic. Yet, we have also set forth our policy in D.02-03-055 that there is value in maintaining the DA market. To guard against DA contracts becoming uneconomic, we stated in D.02-07-032 that "there should be a cap on the total surcharge levels imposed on DA customers (including the impact of any changes to PX credits)."

In order for contracting for direct access to reopen in California, legislation is likely required. Direct access stakeholders have begun to seek legislative action now that the utilities have resumed electricity procurement, the electricity bonds have been sold and exit fees have been set.

Drivers of Demand on the Customer Credit Account

SB 1038 limits eligibility for customer credits as follows:

Section 383.5 (f)(1) of the Public Utilities Code:

> Ten percent of the funds collected pursuant to paragraph (6) of subdivision (c) of Section 381 shall be used to provide customer credits to customers that entered into a direct transaction on or before September 20, 2001, for purchases of electricity produced by registered in-state renewable electricity generating facilities.

This language limits customer eligibility to those with a valid direct access contract prior to the suspension date and who purchase eligible renewable power. Because direct access load is about 14% of load in the state served by the investor owned utilities, demand could increase for Customer Credit Account funds in 2003 subject to the limits in the bill:

383.5 (f)(2)(B) Public Utilities Code

> … Credits awarded to members of the combined class of customers, other than residential and small commercial customers, may not exceed one thousand dollars ($1,000) per customer per calendar year. In no event may more than 20 percent of the total customer incentive funds be awarded to members of the combined class of customers other than residential and small commercial customers.

Before direct access contracting is reinstated, the number of customers and amount of load on direct access will be driven by the economics of the direct access market and other market rules. In all cases, the CPUC has been clear that the goal is to cap the load served via direct access while contracting is suspended. Thus, only reductions in total direct access load potentially eligible for customer credits will occur prior to suspension being lifted.

The extent to which reductions in direct access load will occur are not predictable because the basic economics of direct access remain unclear. Although the CPUC has ordered a cap imposed on exit fees, the level of the cap will be reevaluated by July 1, 2003 and could increase. Customers have argued that even the current cap level will make some contracts uneconomic and drive customers to return to bundled utility service. In addition, the procedures for calculating the credit direct access customers receive from the utility for avoiding generation procurement is under review, which could have a positive or negative impact on the economics of direct access customers. Changes to programs and tariffs under proceedings such as the demand response proceeding (R. 02-06-001) could cause changes to the competitive landscape that draw direct access customers back to utility bundled service.

Direct access eligibility rules related to the suspension of contracting also remain contested. For example, a decline in total direct access load is guaranteed to the extent that, over time, some customers will move out of a service territory, close a business location or otherwise cease service. However, some parties are now in the process of attempting to modify commission decisions to allow a customer with a set of locations to replace direct access load that ceases service with load from another location without direct access service. Also, the implications of California's Renewables Portfolio Standard Program on direct access customers are unknown because the proceeding for that purpose has just been initiated.

For all of these reasons, it is impossible to predict the size of the direct access load reduction of any of these drivers due to the confidential nature of direct access contracts. In one scenario, demand for customer credit funds could dwindle to zero if existing eligible customers are driven back to utility bundled service by the impacts of exit fees or other rules. In another scenario, the existing demands on funds could remain, with increasing demands from the existing non-residential, non-small commercial customers up to the limits set in SB 1038.[6]

When suspension of direct access is lifted, SB 1038 will continue to limit customer credits to direct access customers with contracts prior to the suspension date. Thus, changes in section 383.5 of the Public Utility Code would be required to expand eligibility to other direct access customers when direct access is reinstated.

Customer Eligibility Adjustments

Adjustments to eligibility requirements for the Customer Credit Account funds could increase demand for the funds and thus increase renewable generation above and beyond the 20% goal set by the California RPS. Funding eligibility might be expanded by customer category or product category. We address the customer eligibility issues first and the product eligibility next.

Expansion of the eligibility requirements to a broader group of customers may be driven by several factors including revocation of direct access suspension, implementation of AB 117, the Community Aggregation bill signed by the Governor in 2002, or potentially by new legislation reopening direct access in full or partial form.

However, before legislative action is taken, the CPUC will set the stage for the potential size and success of the competitive retail market in its procurement proceeding, R.01-10-024, where it is addressing the utilities' long-term procurement plans. As with similar proceedings in other states, utility procurement for default service customers (all those who are not served by a competitive supplier) is dynamically intertwined with the potential for robust retail electricity choice. Particularly in California, the scale and length of DWR and other long-term contracts will dictate the availability of load reductions to utility bundled service without the imposition of additional exit fees to collect stranded costs. To the extent that "free" load reductions are limited, energy efficiency, demand response, distributed generation and direct access effectively compete for expansion opportunities. Thus, the potential for growth in demand for Customer Credit Account funds will be driven, in part, by the decisions in the procurement proceeding.

Customer representatives are pushing for more choices. The Bay Area Economic Forum released a report in November 2002, "California's Energy Future: A Framework for an Integrated Power Policy,"[7] that identifies the spectrum of options available for the next vision of California's electric public policy. The Forum, a partnership of the Association of Bay Area Governments and the Bay Area Council, recommends that customer choice be reintroduced and encouraged in California. The report offers a variety of alternatives for retail electricity choice that are being used in other markets, from bidding out default service to a core/non-core split for choice eligibility.

In either the case where large customers are offered choice again, but small customers are not, or the current situation where larger customers have access to funds but are limited in total funding and funds per customer per year, the demand for customer credit funds could increase further if the caps are relaxed on annual funding per large customer and the limit on the total funds going to the large customer category.

The Community Aggregation bill, AB 117, has spurred interest from small customer advocates for more choices. The Customer Credit Account was set up to focus resources on small customers, and with the implementation of AB 117, growth in demand for customer credit funds could be strong, should adjustments be made in eligibility rules to allow it. In Ohio, the Northeast Ohio Public Energy Council[8], an aggregation comprising about 400,000 residential customers, competitively procured electric service and is being served with cleaner energy blend than the default service offered by the utility. The Customer Credit Account could serve as a stimulus for Community Aggregation around renewable energy choices. However, because SB 1038 limits eligibility for Customer Credit Account funds to those with contracts signed before the suspension of direct access, this legislative provision would have to be relaxed or removed in order for community aggregation contracts to be supported by Customer Credit Account funds.

As evidenced in Texas, the competitive retail renewable market and the policy-driven wholesale renewable market are symbiotic. Wind plants are being built faster than required by the RPS with near-term, shorter duration contracts from competitive suppliers for wind attributes (RECs) supporting the gap. Green Mountain Energy Company reports that its customers support 150 MW of wind in Texas.

The legislature will determine whether and when to adjust statutory eligibility requirements for customer credits. Adjustments in customer eligibility driven by changes in direct access rules or law could quickly and sharply increase demand for customer credit funds.

Product Eligibility Adjustments

Due in large part to the success of competitive renewable energy retailing in California, supported by the Customer Credit Account, customer-driven demand for renewable energy has spread widely in the past three years in the United States. The National Renewable Energy Laboratory (NREL) concludes that competitive retail renewable energy products are available in 8 states, regulated green pricing programs are available in about 200 utility service territories in 32 states and nearly 40% of U.S. customers now have access to a green power product from a competitive retail supplier or through a utility green pricing program.[9] NREL calculates that 400,000 customers are now purchasing green power, and more than 1,000 MW of new renewable power plants are installed or planned to serve the combined customer-driven demand in the three primary markets: the competitive retail market, the regulated utility green-pricing market, and the national retail renewable energy certificates (RECs) market.[10] Customers in all states have access to retail RECs[11] from about a dozen companies.

California launched this explosion in 1998 with competitive renewable energy products. Success with the competitive market and with early utility green pricing programs, like that of the Sacramento Municipal Utility District, led to the proliferation of green pricing programs in regulated markets. In just the last two years, the RECs market has exploded. As explained more fully in the next section, the wholesale renewable energy market now functions almost exclusively on a RECs basis.

The retail market has found that larger customers, commercial, industrial and institutional, take the time to become educated about renewable energy and have become comfortable buying a RECs product unbundled from accompanying electricity. A bundled renewable power product is usually composed of RECs matched with real-time, full-requirements commodity electricity. RECs retailers report that once a customer understands that RECs can be matched with any electricity source to create "green power" they are likely to be willing to consider purchasing RECs without making any changes to their electricity service.

Another factor in the growth of retail RECs is the very recent set of programs and certification opportunities that welcome RECs as a legitimate way to support renewable energy and provide positive environmental benefits. The Center for Resource Solutions, an independent not-for-profit, which certifies green power products, now certifies RECs.[12] The EPA's Green Power Partnership allows Partners to qualify by purchasing green power products or RECs products.[13] The U.S. Green Building Council, which administers the LEED™ rating system, has recently revised its green power eligibility rules to allow RECs to qualify for 1 of 17 energy related rating credits.[14]

Today, California customers buy retail RECs products from a variety of vendors in small volumes. Because RECs are sold separately from commodity electricity, a customer can remain with bundled utility service and still buy RECs to support renewable energy. Thus, expanding the products eligible for Customer Credit Account funds to include RECs would not require changes to direct access rules, but could increase California's demand for renewable energy.

Research performed for the Energy Commission indicated that RECs vendors have shied away from California due to regulatory uncertainty in the electricity market generally, as well as uncertainty with rules specific to renewable energy markets. However, all contacted RECs vendors expressed an interest in the California market if the regulatory issues were resolved and customer credit funds were made available to support RECs sales in California. One of the key regulatory issues for tag vendors is the development and implementation of a registry and accounting systems for renewable energy in California.

RECs are also being sold through regulated utilities by competitive suppliers in programs in Oregon and New York. California's legislation does not contemplate this kind of a program, but it is possible that Customer Credit Account funds could be used to support this style of a program, increasing customer-driven demand for renewable procurement beyond RPS goals, without resumption of direct access. The Oregon and Niagara Mohawk programs are discussed in detail in Appendix C.

Other Renewable Energy Program Funding Demands

The California RPS holds great promise for more than doubling the renewable energy procurement in the state. The sufficiency of funds in the New Account for supplemental energy payments to support procurement of renewable energy to meet the 20% goal is unknown. Scenarios evaluated by the Energy Commission show that funding sufficiency is very sensitive to the supplemental energy payment level among other factors. Plausible scenarios show that the New Account alone will sufficiently fund the California RPS goal of 20% renewable energy, and other plausible scenarios show that total funds from all Accounts are insufficient to meet the 20% goal. Assessing the relative probability of scenarios will depend on the methodology selected to determine the SB 1078 market price, the timing of PG&E and SCE's return to credit-worthy status, the procurement plans adopted for the utilities by the CPUC, growth in electricity demand, and the evolution of renewable and conventional wholesale power markets generally.

The intent of the legislature was to set up a portfolio of funding methods for existing, new and emerging renewable energy technologies. The Customer Credit Account has been a successful element of that strategy. Demands for increased funds may occur in the New Account, but the level of that demand cannot be forecast until the rules are developed for RPS procurement. The Emerging Account has had demand significantly greater than allocation of funds for the last two years. The Existing Account, representing 20% of the total funds, has had significantly lower demand than funds allocation in the last two years, a situation expected to continue.

The Energy Commission must decide if and when to transfer funds from Accounts with lower demand to Accounts with higher demand. At this time we cannot predict whether or when the New Account will need additional funding, whereas the Emerging Account has high probability immediate needs. Funding requests for the Customer Credit Account are currently at about 35% of the allocation whereas the Existing Account will likely have very little funding demand and double the allocation of funds compared to the Customer Credit Account. Thus, if funds are needed for reallocation to the Emerging or New Accounts in the near term, the Existing Account funds are another potential funding source.

Beyond demands for funding from the direct users of the Accounts, the California RPS creates a need for funds to support the development, construction and operation of an accounting system for which the Energy Commission is responsible. An option for use of reallocated funds from the Customer Credit or Existing Accounts would be to support the New Account and RPS by creating an accounting system that maximizes RPS compliance flexibility and minimizes compliance costs.

Options for Effective Use of the Customer Credit Account

Historically, the Customer Credit Subaccount successfully supported renewable energy demand. During the first phase of the program, the customer credit level dropped by a third from the statutory cap of 1.5 c/kWh to 1 c/kWh reflecting the increase in demand for the funds. At 1 c/kWh, the Customer Credit Account credit level is equal to the Existing Account payment cap. The CEC will not know the level of supplemental energy payments from the New Account for renewable energy procurement in compliance with the California RPS until rules are established and procurement begins. The CEC has the flexibility to reduce the customer credit level further based on increased demand for funds or to match the level of supplemental energy payments.

Options available to the CEC and legislature to effectively use customer credit funds include the following:

- Support existing, eligible direct access customers at the current credit level, equal to the payment cap on the existing account, up to the legislative funding limits;
- Relax either or both the per customer and aggregate funding limits for large customers to expand demand for renewable energy among existing, eligible direct access customers;
- Adjust customer eligibility rules to include either or both community aggregation customers and new direct access customers after direct access is reinstated;

- Adjust product eligibility rules to include retail RECs sold directly to customers or through utility programs;
- Reallocate excess Customer Credit Account funds to the New or Emerging Accounts immediately or on an as needed basis;
- Reallocate a portion of the funds to develop, construct and operate the RPS accounting system required of the Energy Commission.

Section 2. U.S. Renewable Energy Certificates Markets

Introduction and Background

Renewable Energy Credits (RECs) are used throughout the world for two primary purposes: 1) as an accounting mechanism to verify compliance with a renewable energy or air quality mandates; and 2) as a commercial mechanism that allows more liquid trading of renewable energy attributes separate from the commodity energy generated by a renewable power plant. In both cases, a REC creates a unique and easily verifiable claim to renewable generation attributes. For this reason, a substantial amount of the wholesale renewable energy sold today from new renewable energy facilities in the U.S. involves REC transactions.

The Energy Commission is considering developing a RECs-based accounting system required by SB 1078 to track compliance with California's RPS. In addition, in evaluating the options available to most effectively use funds in the Customer Credit Account, the Energy Commission is assessing the value of expanding product eligibility to retail RECs, which can be sold to customers to support renewable energy without requiring a change in electricity suppliers.

RECs represent the separable bundle of non-energy attributes (environmental, economic and social) associated with the generation of renewable electricity. RECs are sometimes also referred to as RECss, green tickets, and tradable renewable certificates. A REC is created for every unit of renewable electricity output (usually denominated in MWh), and no more than one REC can be created for any given unit of generation. In this report, we use the term REC in its broadest definition to mean simply the attributes of a given unit of renewable generation, separated from the underlying electrical energy.

The rapid adoption of RECs for regulatory and commercial purposes stems, in part, from the mismatch of renewable generation and consumption profiles. Because most renewable energy requirements (and customer demands for renewable energy) require an annual compliance demonstration, a minute-by-minute match of renewable generation and consumption is unnecessary. For their part, RECs provide a flexible mechanism for intra-year banking of renewable generation attributes that compensates for the fact that renewable energy cannot be easily stored to match a specific customers' load and that some renewable resources are intermittent. In some cases, inter-year banking of RECs is allowed, and RECs make such banking easy to track.

RECs are increasingly used in both retail and wholesale electricity markets by generators, wholesalers, brokers, agents, retailers and customers as a commercial accounting mechanism for renewable energy, and by environmental and utility regulators to demonstrate compliance with state renewable energy purchase mandates, verification of environmental claims, and other energy and environmental obligations. In particular, several U.S. states, Europe and Australia all use RECs as the accounting tool to measure and track renewable generation.[15] New uses for RECs are continually emerging as electricity markets evolve and as businesses create new ways to sell and finance renewable projects. For example, unbundled RECs are increasingly being sold directly to customers to satisfy "green power" demands.

RECs can be generated and claimed by any renewable generator inside or outside of an official system. A central registry, or "Issuing Body" ideally generates official certificates, electronically or on paper, assigning property rights to the generator for the RECs. Because RECs are intangible, a central registry allows independent verification of meter data from facilities to confirm electricity and thus certificate generation and creates a unique identification code for each certificate allowing for verification that certificates are not being sold in multiple locations. This registry, or another entity, may serve as a repository of "retired" or "consumed" RECs as well as a clearinghouse or trading platform for RECs purchases and sales.

The U.S.EPA is funding work to formally establishing a North American Association of Issuing Bodies, including establishing a governance structure for the AAIB, development and negotiation of the agreements governing the interaction of the Issuing Bodies with AAIB and with each other to ensure compatibility of information transfer between Issuing Bodies.[16] Such coordination is required to independently confirm that RECs retired in one system are not also being retired in another system. The Energy Commission is participating in the Western Governors' Association process to establish a comprehensive Western RECs system to match the WECC electricity market territory.

RECs as a Commercial Vehicle in Renewable Wholesale and Retail Markets

RECs are a convention in the renewable wholesale and retail markets. The vast majority of wholesale renewable transactions today include a RECs transaction. All registered wholesale renewable transactions in Texas and New England employ RECs, as are the majority of wholesale renewable transactions in the Mid-Atlantic and the Pacific Northwest regions, which have been dominated by wholesale tag players like Community Energy, PacifiCorp Power Marketing and Bonneville Environmental Foundation. The Center for Resource Solutions, an independent not-for-profit, which certifies green power products, now also certifies RECs.

In California, RECs are in commercial use and also have a statutory basis. SB 1038 specifically identifies that the environmental attributes for two net-metered renewable projects, their RECs, remain the property of the facility owner. The DWR contracts signed with wind generators specifically excluded the sale of RECs to DWR. On the retail side, the APX has operated a "green ticket" exchange in California for the last four years, serving the direct access market. Businesses with locations in California have become members of EPA's Green Power Partnership by purchase RECs. Even California state buildings seeking LEED™ certification now have the opportunity to qualify for 1 out of 17 possible energy-related credits buy purchasing RECs.

Today, California customers buy retail RECs from a variety of vendors in small volumes. Because RECs are sold separately from commodity electricity, a customer can remain with bundled utility service and still buy RECs to support renewable energy. Thus, should the legislature decide to expand the products eligible for Customer Credit Account funds to include RECs, no changes would be required to direct access rules.

Research performed for the Energy Commission indicated that REC vendors have shied away from California due to regulatory uncertainty in the electricity market generally, as well as uncertainty with rules specific to renewable energy markets. However, all contacted REC vendors expressed an interest in the California market if the regulatory issues were resolved and customer credit funds were made available to support REC sales in California. One of the key regulatory issues for REC vendors is the development and implementation of a registry and accounting systems for renewable energy in California.

RECs as an Accounting Mechanism for Renewable Transactions

RECs are used as an accounting mechanism for governments implementing RPS policies. There are presently eight states that are using or that plan to use RECs for RPS compliance purposes: Arizona, Nevada, Texas, Massachusetts, Maine, Connecticut, New Jersey, and Wisconsin. The Texas and New England systems are currently the most well-developed and advanced of these systems.[17] Other countries that have developed RPS policies have universally turned to REC systems to monitor and verify compliance with those policies, e.g., Australia, the United Kingdom, Italy, and Belgium.

Though not used for RPS compliance purposes, the California Energy Commission was the first regulatory agency in the U.S. that recognized RECs by allowing their use for verification purposes for the Renewable Energy Program's Customer Credit Account. The Automated Power Exchange's (APX) California RECs market has been in operation for four years and has been a one-stop-shop for retailers or customers looking to purchase RECs and generators or wholesalers seeking to sell them.

The concept of RECs has recently been adapted in the Northeast to provide an accounting mechanism for all forms of electricity. In this context, market participants use the terms 'generation attributes,' or simply 'certificates,' to refer to the attributes of any form of electric generation, e.g., coal certificates, nuclear certificates or natural gas certificates. A full generation certificates system such as the one in place in New England affords utility and environmental regulators the ability to easily and effectively monitor compliance with RPS requirements, generate fuel source and emissions disclosure labels for electricity products, and verify compliance towards air pollutant emissions requirements.

REC systems issue a unique certificate for every unit of renewable electricity generation (typically, each MWh). By then tracking that certificate through intermediate transactions from the renewable generator to the load serving entity (LSE), state regulators can easily determine whether a load serving entity has met its renewable energy mandate. RECs can be used for accounting purposes whether RECs are transacted separately from or bundled with electricity, though as discussed later in this report, a principal benefit of RECs comes in their ability to be transacted separately from electricity.

RPS Accounting Options

SB 1078 gives the Energy Commission the authority and responsibility to design and develop an accounting system to track RPS compliance, to prevent double-counting of renewable energy output, and to allow for the verification of product claims inside or outside the state:

> 399.13. The Energy Commission shall do all of the following:
>
> (b) Design and implement an accounting system to verify compliance with the renewables portfolio standard by retail sellers, to ensure that renewable energy output is counted only once for the purpose of meeting the renewables portfolio standard of this state or any other state, and for verifying retail product claims in this state or any other state. In establishing the guidelines governing this system, the Energy Commission shall collect data from electricity market participants that it deems necessary to verify compliance of retail sellers, in accordance with the requirements of this article and the California Public Records Act (Chapter 3.5 (commencing with Section 6250) of Division 7 of Title 1 of the Government Code). In seeking data from electrical corporations, the Energy Commission shall request data from the commission. The commission shall collect data from electrical corporations and remit the data to the Energy Commission within 90 days of the request.

Though REC systems, or certificates systems more generally, are increasingly the tool of choice in accounting for RPS requirements, alternatively a contract-path system, can be employed. Below, we summarize these two basic accounting systems, and describe the general advantages and disadvantages of each.[18]

Contract Path Systems

Contract path systems use bilateral contracts and receipts (a "paper trail"), usually going back to the generator, to verify the quantity and characteristics of the generation attributes purchased or sold. Contract path tracking systems are typically associated with transactions where the energy and attributes remain bundled together.

Generally, a company's product or portfolio mix is considered to be a sum of its electricity contracts. Nearly all contract path systems are characterized by a third party review, usually an auditor, of sworn attestations, contract receipts and other proof of generation and transfer of ownership (e.g. between a generator, intermediary, or final marketer). Meter data is sometimes used to verify such attestations and contracts. This is the method that has been used by the Energy Commission to verify Customer Credit Subaccount fund distributions and the power source disclosure requirements of SB1305, though the Energy Commission has also allowed the use of RECs in certain circumstances.

Certificate-Based Systems

In principal, contract-path tracking could also be used to verify the sale of RECs. However, using a paper trail of REC purchase and sales contracts, after the fact, is a more cumbersome and less secure way of verifying REC transactions than using a fully functional electronic REC system.

Two key differentiating characteristics of certificate systems from contract path systems are therefore (1) that the mere possession of a REC is proof of ownership of the underlying generation attributes, and (2) that certificates are tracked electronically from "cradle to grave." Unlike under contract path systems, regulators therefore need not use a paper trail to track RECs and manual review of contracts is unnecessary in establishing REC ownership.

Under certificate tracking systems, RECs are electronically issued for each unit of recorded renewable generation. Individual RECs are identified by a unique serial number. REC ownership is tracked electronically, and all REC trades are recorded in electronic accounts (much like electronic bank accounts). At the end of an RPS compliance period, regulators can easily check the REC accounts of electricity suppliers to determine if those suppliers own sufficient RECs to meet their RPS requirements.

Certificate-based systems also generally allow RECs to be "unbundled" from the underlying electricity and sold separately from electricity. Thus, another defining characteristic of certificate tracking systems is the unbundling of electricity attributes from energy flow.[19] The RECs can then be freely traded in secondary markets

Advantages of Certificate-Based Systems

Certificate or REC based systems are now widely considered superior to contract-path tracking, and are in increasing use worldwide. Some of the specific advantages of certificate systems are highlighted below.

Ease of Administration: Certificate-based systems are easy to administer and use because they track RECs with simple automated systems. Unique REC ownership is easily determined by a review of the electronic accounts. Unlike contract path systems, there is no need to follow a daisy chain of electricity contracts to determine renewable energy attribute ownership. Reliance on attestations and a review of paper contracts is similarly unnecessary. Though certificate systems may be somewhat more costly to establish initially, the ongoing costs and staff requirements are low. As the number of market participants increases, the ease of administering a REC system becomes all the more important. Based on the Energy Commission experience administering and operating a contract path accounting system for the Customer Credit Subaccount and the Environmental Disclosure Program, we believe it would be challenging to administer a contract path verification system for the RPS, especially considering the fact that the RPS applies to both IOUs and ESPs.

Banking and Borrowing for Compliance Flexibility: SB 1078 requires that the CPUC adopt flexible compliance rules for the RPS "including, but not limited to, permitting electrical corporations to apply excess procurement in one year to subsequent years or inadequate procurement in one year to no more than the following three years." In other jurisdictions, such flexibility mechanisms are sometimes referred to as "forward banking" and "deficit borrowing," respectively. Certificate-based systems can then be designed to easily accommodate the desired flexibility mechanisms. For example, a RECs system could establish compliance subaccounts for various years, and allowing an IOU to transfer certificates between subaccounts, or to borrow from future subaccounts. Borrowing would occur by increasing the compliance requirements in a future compliance period.

Baseline Monitoring and Verification: SB 1078 requires that the CPUC establish "an initial baseline for each electrical corporation based on the actual percentage of retail sales procured from eligible renewable energy resources in 2001, and, to the extent applicable, adjusted going forward pursuant to subdivision (a) of Section 399.12." RECs can include information on the age of the generation facility and its eligibility for meeting the baseline quantity or for meeting the incremental RPS commitments. Once the REC is identified as counting toward the baseline quantity of an electrical corporation, it could automatically be credited to the IOUs "baseline" subaccount. Facilities that add incremental new generation to an existing facility could also be accommodated such that a percentage of the output is marked as baseline and the remainder is marked as incremental. Alternatively, within a single year, all certificates owned by an electrical corporation up to the pre-determined baseline quantity could be marked as baseline, with all RECs thereafter during the year marked as incremental.

Assurance of No Double Counting: An RPS accounting system must be able to assure that renewable generation attributes are not "double counted" or otherwise used impermissibly. An electronically based REC system all but assures that double counting of tags from registered generators does not occur.[20] Only REC ownership allows a purchaser to claim the generation attributes, and only a single REC is generated for every unit of electricity generation. Under a contract-path tracking system, on the other hand, regulators must rely on paper contracts, attestations, and after-the-fact reviews. Assurance of double counting cannot be provided as firmly and securely as under a certificate system. For example, under a contract path system a utility may be able to demonstrate that they have purchased renewable electricity through a contract showing, but that same IOU would not be able to uniquely prove that no other supplier has asserted the same claim.[21]

Cost Minimization: RECs are commonly used in wholesale markets to facilitate renewable electricity trading. This is because RECs offer a uniquely flexible compliance tool for utilities and ESPs. For example, if renewable generation is most cost-effectively developed in Northern California, RECs allow renewable development to occur in the Northern part of the state, with RECs sold to utilities or ESPs throughout the entire state without the need for direct electricity transmission to those areas. This ensures that renewables development will occur in the lowest cost areas, and will not be "forced" in higher cost areas simply due to transmission constraints.

Similarly, if one of the state's IOUs substantially over-complies with their RPS, RECs allow that IOU to dispense of its excess compliance to other, non-compliant utilities or ESPs.

Facilitation of ESP Participation in the RPS: Under SB 1078, ESPs are required to comply with the RPS over time. Some ESPs will have RPS requirements that begin in 2002. Many ESPs, however, will be hard pressed to meaningfully participate in the RPS requirement. As with PG&E and SCE, who are not yet credit-worthy, many ESPs lack the credit that would be necessary to support the financing of new renewable generation. Moreover, with uncertain and small customer loads, many ESPs will also be hard pressed to match intermittent or variable sources of renewable electricity generation with their customer loads. Thus, many ESPs will be unable to offer attractive long-term electricity contracts to renewable generators. With a REC system, however, a renewable generator may be able to find a willing buyer for the electricity from a larger, credit-worthy counter party, with RECs then sold to the ESP. Such transactions will often be preferable to both the generator and the ESP.

Lower Transaction Costs for Market Participants: REC systems may also impose a lower transactional burden on market participants: renewable energy generators, IOUs, and ESPs. Rather than tracking individual contracts and using attestations and costly third-party audits to verify the purchase or sale of renewable generation, electronic systems simplify the renewable energy contracting and verification process. Related, RECs provide the most flexible compliance mechanism for the RPS because, if allowed by regulation, RECs can be banked, borrowed, or traded quite easily.

Due to these numerous advantages certificate-based systems have emerged as the most common method for accounting for renewable generation and for preventing double-counting of renewable generation. New England, having attempted and failed to design an effective contract-path system, recently switched to a certificates system. Nevada, a state with an RPS that borders California, has also recently endorsed the use of a REC compliance system for their RPS.

Adaptability of RECs to Other Compliance and Accounting Requirements

SB 1078 requires that the Energy Commission's accounting system not only serve RPS compliance purposes, but also be used for "verifying retail product claims in this state or any other state." The Energy Commission takes this language to mean that, at a minimum, the accounting system is to also be used to verify compliance with the State's power source disclosure requirements (SB 1305) and to monitor the possible future disbursement of funds from the Energy Commission's Customer Credit Account.

As the wholesale renewable electricity market, and thus the RECs market has evolved, market participants and regulators have acknowledged the need for reconciliation of claims and RECs transactions across borders. The Energy Commission is currently working with a group organized by the Western Governor's Association to investigate the potential of a WECC-wide RECs tracking system. In addition, there is an effort to form a national RECs tracking network with a central American Association of Issuing Bodies that would link states and regions that have certificate based systems. All of these efforts would support California's use of the RECs approach.

As the uses of the Energy Commission's accounting system increase, so to does the need for simplified verification and assurance of no double counting. As already clearly indicated, because certificate-based systems are highly automated, they have great flexibility and expandability: a REC system is likely best able to serve the multiple needs contemplated by SB 1078.

The creation of a certificate-based accounting system may also have ancillary market benefits that are consistent with the CPUC and Energy Commission's goal of increasing renewable generation in the State. These benefits may come from the facilitation of (1) retail REC-only products, and (2) the use of RECs in pollution credit markets:

Retail REC-only Product: RECs are being sold separately from electricity in California and across the country as a stand-alone product to end-use customers. There are currently about a dozen companies that are featuring RECs as a stand-alone "green power" product. These types of products are frequently marketed to consumers on the internet by independent companies not serving electricity load. In addition, programs in Oregon and New York now allow RECs from competitive suppliers to be sold through utility programs.[22] The creation of a REC establishes property rights and creates a currency that can be bought or sold individually from electricity by end-use customers. By developing a certificate-based accounting system for RPS compliance, California will therefore also create a system that may facilitate and expand customer-driven demand for renewable energy in, and potentially outside, the state.

Pollution Offset or Environmental Compliance: RECs may in the future be used in pollution credit markets. To do so, RECs must be converted from an energy tool measured in MWh to a pollution tool, denominated in units of pollution. Depending upon the pollution offset credit being calculated, there may be the need for information on the date and time of generation, geographic location of the generator, as well as the location to which the energy was sold. Although there are few examples in the U.S. where a REC has been converted into a pollution offset or pollution credit for environmental compliance purposes, RECs are regularly used by large companies and others that want to voluntarily reduce their emissions profile, or boast of a climate neutral footprint. In addition, EPA's Green Power Partnership program promotes the purchase of RECs by businesses and has lead discussions about how RECs may be used in the future in state or federal emissions trading programs.[23]

Appendix A. The Texas RPS and RECs Tracking System

Texas has rapidly emerged as one of the leading wind power markets in the United States. This development can be largely traced to a well-designed and carefully implemented renewables portfolio standard (RPS). To meet the state's RPS requirement, Texas was the first U.S. state to develop a fully functional system for tradable renewable energy credits (RECs). Here we briefly discuss the design of the Texas RPS and provide a more detailed account of the RECs system that was created to account for and verify compliance with the RPS.

Texas RPS Summary[24]

In May 1999, the Texas government established an RPS within the restructuring of the state's electricity market.[25] Detailed RPS regulations were subsequently established by the Texas Public Utilities Commission.[26] The regulatory process to design the rules of the Texas RPS began in June 1999 and proceeded rapidly, with final rules completed in December 1999. The Texas ISO, ERCOT, was appointed to be the program administrator of the RECs program in May 2000. Texas' RECs system began operations 18 months after rules were set, in July 2001, with the first RPS obligations applied in 2002.

The Texas RPS requires the installation of 2000 MW of new renewable capacity by the year 2009, in addition to preserving the 880 MW of renewable energy already on line. This translates to about 3% of present electricity consumption.[27] This goal is modest relative to the enormous potential for renewable energy development in Texas, but it represents a marked increase in renewable energy capacity in the state.

Intermediate new renewable capacity goals in Texas are 400 MW by 2003, 850 MW by 2005, 1400 MW by 2007 and finally 2000 MW by 2009. These capacity goals are translated into megawatt-hour based energy requirements by using an average capacity factor of all eligible renewable plants; its value is initially set at 35% and will be adjusted over time based on actual plant performance.

Electricity retailers that serve markets open to competition are obliged to fulfill their portion (based on yearly retail electricity sales) of the renewable energy requirement by presenting RECs to the regulating authority on an annual basis. The obligation begins in 2002 and ends in 2019.

A tradable REC is issued for each MWh of eligible renewable generation located within or delivered to the Texas grid, meaning the entire Texas grid, including areas outside of ERCOT. With the exception of renewable power plants with a capacity smaller than 2 MW, which are eligible irrespective of their vintage, the REC trading program is restricted to facilities erected after September 1, 1999. A wide variety of renewable technologies are eligible.

Table 1 summarizes the design features of the policy.

Table 1: The Texas RPS: Design Details.

Design Element	**Design Details**
Renewable energy purchase obligations of eligible new renewable generation	Capacity targets: 2003 - 400 MW 2005 - 850 MW 2007 - 1400 MW 2009 - 2000 MW (through 2019) Annual energy-based purchase obligations: begin in 2002 and end in 2019 derived based on capacity targets and average capacity factor of renewable generation (initially set at 35%)
Obliged parties	Who: All electricity retailers in competitive markets (80% of total Texas load.) Publicly-owned utilities must only meet the RPS if they opt-in to competition. Metric: obligation based on their proportionate yearly electricity sales;
Eligible renewable energy sources	Vintage and Size: new renewable power plants commissioned after September 1, 1999 and all renewable plants less than 2 MW capacity, regardless of date of installation RECs Offset Vintage: purchases of renewable energy from plants larger than 2 MW and built before September 1999 may count towards a supplier's REC obligation, but are not tradable Resources: solar, wind, geothermal, hydro, wave, tidal, biomass, biomass-based waste products, and landfill gas Location: facility must be located within or delivered to the Texas grid DG and DR: renewable energy sources that offset (but do not produce) electricity (e.g., solar hot water, geothermal heat pumps), and off-grid and customer sited-projects (e.g., solar) are also eligible
Tracking and accounting method	Method: tradable renewable energy certificates Compliance Period: calendar year Grace Period: 3 month grace period allowed for fulfillment after compliance period ends Operations: web-based certificates registry, tracking and retirement
Certificates	Creation: issued on production, 1 REC/MWh Banking: 2 years of banking allowed after year of issuance, borrowing of up to 5% of the obligation in first 2 compliance periods allowed
Regulatory bodies	Regulator: Texas Public Utilities Commission establishes RPS rules and enforces compliance Administrator: ERCOT Independent System Operator
Enforcement	Penalty: the lesser of 5(U.S.)¢/kWh or 200% of mean REC trade value in compliance period for each missing kWh

Texas's RECs Policy Background

Texas developed the first comprehensive RECs system in the U.S., a web-based platform that provides for the issuance, registration, trade, and retirement of RECs. The platform facilitates the tracking of RPS compliance, but does not provide the "market making" function of a certificate exchange, as this function is to be the left to the private marketplace, as will REC brokering and financial markets.

Texas' RPS was contained within the state's electricity restructuring legislation, and that legislation also specified that RECs were to be used to meet the policy's goals. Texas' RPS rules, completed in December 1999, laid out the broad design of the Texas RECs program. In May 2000, the Public Utility Commission of Texas (PUCT) assigned the REC program design and administration responsibilities to the Electric Reliability Council of Texas (ERCOT). ERCOT subsequently developed detailed operating rules for the RECs program (with the help of a consultant, and with detailed public workshops and comments from stakeholders), which were completed in late 2000, and issued an RFP to identify a contractor to build the system's software. The Automated Power Exchange (APX) was tapped to build the software in late December 2000, and the system was completed and delivered to ERCOT in April 2001 (approximately 4 months after APX was selected to build the software). The REC Program, which only tracks renewable energy certificates, started operating in July 2001and has been in operation for a year and a half.

There are two categories of certificates in the Texas REC Program: Renewable Energy Credits (RECs) and REC Offsets. A REC is from a new renewable facility; a REC Offset is from an existing renewable facility. Pursuant to Texas law, only RECs may be traded.

Texas's RECs Operational History

Though designed principally to meet RPS compliance needs, Texas' RECs system has also found other uses. In particular, it is used by green power marketers to procure renewable energy in Texas. Texas RECs have also been purchased by out-of-state entities for the purposes of green power marketing and green claims.

Currently there are about 950 MWs of new renewable generation capacity in Texas, which will result in approximately 2.5 million RECs created during 2002. ERCOT, as the Program Administrator, is currently managing over 150 market participant accounts (some market participants have multiple accounts), 54 of which are competitive retailers in the new Texas restructured electric market (the remainder include 23 REC generators, 19 brokers, 28 traders, 11 exchanges, 10 aggregators, and 10 other). REC account holders include participants from several states outside Texas and at least two countries other than the U.S.

Most of the new renewable projects in Texas have sold their electricity and RECs in a bundled fashion to large retail electricity providers under long-term (10-20 year) contract. With 950 MW of new renewable generation on-line, and just a 400 MW RPS requirement in 2002, these larger electricity providers have subsequently sold some of their RECs to other parties in and outside of the state. RECs were traded during early 2002 at $4/MWh. Since then, due to transmission constraints and other factors (including the possibility of some market power), REC prices have risen. REC prices reportedly reached a high of $17-18/MWh over the summer, and by the end of 2002 receded to approximately 12/MWh. Prices have been generally lower for future RECs delivery, at $6-9/MWh for RECs generated in 2005.

Texas RECs Participation

Participation in the REC program is mandatory only for retail electricity providers (described more generally here as load serving entities, or LSEs) participating in the competitive retail market in Texas, who must therefore meet RPS obligations. Renewable generators and REC aggregators (who are aggregating RECs from small-scale renewable generation units) also participate in the program because it is the only way to sell RECs for purposes of RPS compliance, though they do so voluntarily. Other parties may also participate in the REC Program, for example, a third party broker that facilitates transactions.

Texas's RECs and REC Offsets Creation

A Texas REC represents all of the renewable attributes associated with one MWh of production from a certified renewable generator. RECs are allocated to certified REC generators on a quarterly basis by ERCOT based on metered production that is electronically transferred to the database.

Each REC issued contains the following information. This information is coded to form a unique serial number for every REC produced.

- Date generated (quarter/year)
- Type of renewable resource
- Facility ID number (assigned by ERCOT; fixed for life of facility, regardless of changes in ownership)
- REC number (numbered 1 through the total number of MWh generated by the facility in a quarter)

REC Offsets are awarded to an existing renewable generation facility based on its 10-year historical average of energy output. Offsets may be used in place of a REC to meet a renewable energy requirement only by that entity assigned the offsets and only when they opt to participate in the newly restructured retail market in Texas. REC Offsets cannot be bought, traded, sold, or retired. The PUCT issues REC Offsets once and the Offsets are good until the PUCT revokes them or until the generating plant is no longer generating electricity. The REC Offsets are held in the Offset generator's account until it assigns those Offsets to the buyers of electricity for their use when they opt into retail competition in Texas.

Texas's RECs Data Source

ERCOT receives metered generation data electronically directly from the generators based on actual measured production on a daily 15-minute basis. This information is downloaded into the REC software on a monthly basis. Data used for calculations is settlement quality data. If the REC generator or REC Offset generator does not have interval metering, the PUCT is obligated to define a methodology for determining the amount of REC generation or REC Offset generation that has occurred.

To calculate the REC requirement for RPS compliance of each LSE, ERCOT requires each LSE to provide monthly load information such that ERCOT can calculate the MWh consumed by Texas customers served by the competitive retailer.

Texas's RECs Generator Registration

REC generators or aggregators must apply to the PUCT for certification to produce or aggregate RECs. Once registered, the PUCT notifies ERCOT of the certification and the REC Generator will log on to the www.texasrenewables.com web site and establish their trading account.

REC Offset generators must have applied to the PUCT for certification by July 31, 2001. After a REC Offset generator is certified, a REC Offset recipient can be identified and certified. The REC Offset generator will deposit the REC Offsets into the recipient's account as described above.

Both REC generators and REC Offset generators can be decertified. ERCOT verifies that generation is occurring when metering is available to do so. If metering is not available, it is the obligation of the PUCT to verify production and assess whether the PUCT's RPS rule is being met.

RECs may also be produced by generators that are not located in Texas if (1) the first metering point for such generation is in Texas and is for Texas use, and (2) all generation metered at the location of injection into the Texas grid comes from that facility. Such generators must also be certified by the PUCT. These rules effectively limit the program to in-state generators.

Texas's RECs Transfer

RECs are easily transferred between account holders through a web-based platform. The act of negotiating the price and other details of the sale or purchase of renewable electricity or RECs alone is negotiated privately through traditional methods. However, the REC transfer does not occur until the initiator or seller requests a transfer on the ERCOT site and it is confirmed by the receiving party. After this occurs, the REC Program will transfer RECs between accounts. REC Offsets may not be transferred to another account holder.

Texas RECs and REC Offsets Retirement

RECs are retired from the system under three circumstances: mandatory compliance (e.g. RPS), voluntary retirement (e.g. green power sale), or expiration. The account holder must designate to ERCOT which RECs it wants to retire for the mandatory or voluntary retirement. ERCOT will automatically retire RECs each year that have expired. REC Offsets are not retired.

Texas RECs and REC Offsets Lifetime

RECs have a useful life for RPS compliance purposes of three "compliance periods," or stated differently, the calendar year in which the REC was generated plus two more full years. If a REC is not used to meet a compliance purpose, it will be retired at the end of the first quarter of the fourth year. For example, a REC generated in 2004 can only be used to meet Texas RPS compliance in the years 2004, 2005, and 2006, but it can still be used for all other purposes, such as private REC sales, until March 31, 2007 when all remaining RECs from 2004 are retired. REC Offsets are considered valid until the PUCT notifies ERCOT that they are no longer valid.

Texas's RECs Information Verification

ERCOT and the PUCT reserve the right to request supporting documentation to allow verification of generation quantities as needed. Non-metered monthly load and generation data are submitted to ERCOT and that information is stored for historical and verification purposes.

Texas RECs Reporting and Public Access to Information

ERCOT is responsible for generating regular reports summarizing the transactions of the REC program. ERCOT publishes a list of REC account holders with contact information to facilitate REC trading, and provides non-competitive information on REC generators, such as facility name, REC ID numbers, resource type, location, etc. ERCOT also posts each month the total aggregate energy sales in MWh of competitive retailers in Texas for the previous month and year to date. Finally, for broader use, ERCOT posts a table that contains the CO_2, SO_2, NO_x and particulate matter emissions data supplied by the PUCT and based on the Texas Natural Resources Commission (TNRC) standards on an emissions per MWh or tons of fuel used basis for each energy type.

The New England Generation Information System

Beyond Texas, the only other fully functional and operational system for tradable certificates in the United States is in New England, where the NEPOOL Generation Information System (NE GIS) tracks all electricity generation via a certificate system in the six New England states (Maine, New Hampshire, Vermont, Massachusetts, Rhode Island and Connecticut.)

GIS Policy Background

The NE GIS and was established to account for various attributes of energy transactions in the NEPOOL transmission region for the purposes of verifying compliance with individual state RPS mandates, emission and power content disclosure statements, and to establish a trading platform to facilitate compliance with these mandates. No financial information is recorded in the GIS database. The system was built by the APX, who is also serving as the Program Administrator for the first five years (unlike in Texas, where APX merely designed the software).

A NEPOOL working group consisting of market participants (generators, marketers, etc.), regulators, and other interested parties developed the design of the NE GIS. The Working Group was formed in 2000, in part as a result of the failure of previous "contract-path" tracking systems to create a seamless regional tracking system. An RFP for the design and administration of the system was distributed in 2001, after which APX was selected. It took the APX approximately 6 months to design the system. Final NEPOOL approval of the operating rules was provided in January 2002, and the system became operational in July 2002.

The cost of developing the NE GIS was $2 million; $500,000 was paid up front during the software development period and the remaining cost is being amortized over the first five years of operation, while APX is serving as the Program Administrator.

GIS Operational History

The NE GIS, which is administered by the Automated Power Exchange, is issuing and tracking about 30 million electricity certificates per quarter over the first six months of its operation. Approximately 6 million certificates were traded during the first quarter of trading. Much of the current trading of certificates is for state RPS compliance purposes. Current prices for GIS certificates eligible for the Massachusetts RPS are $20-25/MWh.

GIS Operational Design

The design of the NE GIS is detailed below. Key features that differentiate this system from the RECs system in Texas are as follows:

More Comprehensive System: The New England system tracks generation not only for RPS compliance, but also for disclosure and emissions regulations. Accordingly, the system generates certificates for all sources of generation in New England, and tracks a greater number of generation "attributes", including emissions characteristics. The New England system is therefore a good model of a system that serves multiple purposes, while Texas offers a simpler solution for just RPS compliance.

Multi-State and Treatment of Electricity Imports: The New England system must account for generation located within the entire multi-state region, and must also account for electricity generation in surrounding regions that is imported into the state. Texas' system need not account for multiple states.

More Rigid Flexibility Rules: The Texas RECs system allows for three years of credit banking and has a calendar year settlement period. The New England GIS system, on the other hand, has a quarterly settlement and trading system for certificates, with no banking. Some market participants have claimed that the limited flexibility in New England is reducing the value of the system for RPS purposes, though the vintage limitations were specifically established so that the system could easily accommodate disclosure and emissions requirements, in addition to state RPS mandates.

GIS Participation

The NE GIS accounts for all generation in NEPOOL central dispatch, both renewable and non-renewable generation. In addition, all LSEs in New England are required to have accounts in the GIS system, with the exception of any LSEs that are not required to meet state mandates, for example some electricity co-operatives or municipal providers. This type of power provider as well as market participants located outside of the NEPOOL central dispatch control area may voluntarily participate in the NE GIS.

GIS Certificate Creation

The GIS administrator issues a GIS certificate for every MWh of generation in the NEPOOL control area or imported into the NEPOOL control area, based on the wholesale energy market settlement data received from the independent system operator. GIS certificates are created on the 15th day of the quarter two calendar quarters after generation has occurred. So, for example, all generation occurring in the first quarter of the year are issued certificates on July 15th. The certificates are numbered; the minimum denomination is one MWh. Once the GIS certificates are created, they are deposited into the generators account, establishing the generator as the original owner of the certificate until it is transferred.

The following information is carried on each certificate:

- Certificate serial number
- Facility name and location
- Fuel type
- Eligibility for regulatory programs in each New England state
- Emissions characteristics for CO, CO2, Hg, NOx, PM, PM10, Sox, VOCs
- Vintage of the generating facility
- Generator installed capacity
- Certificate born on date (mm/yy)
- Control area (interconnect)
- Labor characteristics
- Green-e registration number

GIS Source of Data

The GIS database uses monthly financial settlement data from the New England Independent System Operator for generation within New England, and for imports and exports to and from the system (smaller generators that the ISO does not "see" will be accommodated in other ways). Transfers and other wholesale transactions are recorded in the database by the parties involved as they occur. Retail load obligations are ascertained by the GIS Administrator based on a combination of information from the system operator and information provided by the load serving entities. Other information about the generating units not accounted for by the system operator, such as labor characteristics or generation information from non-NEPOOL generators, can be provided to the GIS administrator directly.

GIS Generator Registration

GIS generators and account holders owning generation outside of the NEPOOL control area must register the disclosure attributes of each of their generating units with the GIS Administrator. This information is included on the certificate when issued. This generator information is verified by state regulatory authorities.

Retail Electric Sales Verification

Retail sales of electricity are recorded in each LSE's account through a mechanism known as a "certificate obligation." One certificate obligation is assigned for every MWh consumed. The certificate obligation can be satisfied by either the direct purchase of specific certificates (for example, renewable certificates purchased from a qualified generator) or can be satisfied with "residual mix" certificates that represent the attributes of the entire system, minus any specific purchases. Direct purchases of certificates are recorded in the GIS database through a transfer of certificates from one account holder to another.

GIS Certificates Transfer

GIS certificates may be transferred through a variety of mechanisms. The NE GIS contains a bulletin board function to allow suppliers to show their GIS certificates available to interested buyers. Buyers and sellers can also arrange transfers of GIS certificates through bilateral contracts or private arrangements. However, the purchase of energy out of the system does not include GIS certificates unless they are specifically transferred. Regardless of the exchange process used, all transfers of GIS certificates between accounts is noted in the GIS database and confirmed by the both parties. GIS certificates are eligible for transfer for roughly 60 days, from the day they are created (15th day of the quarter) until 15 days before the end of the quarter.

GIS Reserve Certificates

Any NE GIS participant that sells renewable certificates directly to an end use customer, separate from electricity, may do so by setting the status of such certificates to a reserved state.

Renewable certificates that are set-aside in reserve must be transferred to a bona fide third party before the end of the trading quarter. At the end of the trading quarter, all reserve certificates will be retired.

GIS Imports Accounting

All energy imported into the control area will be accounted for through the creation of GIS certificates for the amount of energy imported. The imported energy will reflect the generating attributes of the specific generation unit if the generator of the imported energy meets all of the following criteria:

- The imported generation is eligible for one of the New England states' RPS;
- The imported generation is settled in the monthly settlements of the New England System operator;
- The generating unit is registered with the NE GIS Administrator and has provided all relevant data needed for the NE GIS Administrator to verify the attributes of such imported energy;
- The energy is imported from a generating unit in an adjacent control area with transmission rights over the ties to the New England Control Area;
- The generator can verify for the GIS Administrator that such energy generation occurred;
- The generator has certified that the attributes have not been sold, retired or otherwise claimed by another party in another jurisdiction; and
- A NERC tag has been issued.

If the imported energy does not meet these criteria, GIS certificates for imported energy will be given the attributes of the most recently available overall mix of fuel sources and emissions of the source control area.

The GIS Administrator will notify the adjacent regulatory agencies on a quarterly basis about the creation and retirement of NE GIS certificates from imported energy.

GIS Exports Accounting

Energy exported from the New England control area will be recorded through a parallel movement of GIS certificates from the GIS account holder's account to the transferee's account. The GIS certificates associated with the exported energy will contain the attributes of the generating facility if essentially the same criteria as imports are met. Otherwise, the exported energy will have the attributes of the residual mix.

GIS Certificates Retirement

The NE GIS is organized in quarterly trading periods. At the end of each trading period, all trading is stopped and all GIS certificates generated during that quarter are accounted for and retired. Any GIS certificates that are not held in an LSE's account are used to calculate the residual mix. The residual mix is simply the weighted average mix of all unaccounted for GIS certificates (equivalent to the generation occurring in the trading period, minus any generation that has been removed through the direct purchase of certificates). Any LSE that has a certificate obligation that has not already satisfied it with purchased certificates is assigned residual mix certificates. After this time, all accounts are closed, reports are available, and a new trading period begins.

GIS Reporting and Public Access to Information

The GIS administrator provides account holders and New England regulatory agencies with quarterly and annual reports, respectively. In addition, there is a publicly accessible portion of the GIS website, www.nepoolgis.com, that will contain a directory of all account holders for the reporting period and, for each account holder, the following information:

- Name, address, phone, fax, website and email,
- Total exports in MWh for the four most recent quarterly trading periods,
- Total number of reserve certificate transactions for the four most recent quarterly trading periods,
- An aggregation and/or average of the certificate fields for all certificates created during the reporting period,
- And for GIS generators,
- Facility ID number,
- Fuel source(s),
- Eligibility under state RPSs,
- Total generation in MWh for the four most recent quarterly trading periods,

And for retail load serving entities,

- Total certificates obligations (retail sales) for the four most recent quarterly trading periods,
- Total imports in MWh for the four most recent quarterly trading periods.[28]

Renewable Energy Credits: Developments in Other States

There are several other efforts underway to develop certificate tracking systems in the U.S. that deserve note.

Wisconsin is developing a system to track renewables purchased by the local utilities in excess of their renewables portfolio standard mandates. The certificates issued are referred to as Renewable Resource Credits (RRC). RRCs are issued to the utilities for any renewable generation that was purchased in excess of the state's renewables mandate in a given year, and was served to utility customers. The RRCs can then be traded between the utilities or held for future compliance. An unlimited banking period for RRCs currently exists in Wisconsin for RPS purposes. The system is expected to be launched in February. The system is being built by Clean Power Markets and Zyquest. The cost of construction is $50,000 and the annual administration and operations are estimated to be $65,000. There was a public input process, including a list-serve for comments and several meetings over the course of about one year. It will take approximately 5 months to construct the system.

In the **Mid-Atlantic**, an ad hoc committee of interested stakeholders has been meeting to discuss the formation of a generation attribute tracking system for the PJM interconnection electricity region. This ad hoc group has recently been officially recognized as a "Working Group" under PJM, which gives it the ability to make recommendations to the PJM System Operator for operational changes. This group is discussing and defining the design features of the certificates tracking system for PJM, which is being expanded to include significant portions of the Midwest and Southeast. The system as currently envisioned by some parties would create certificates for all energy attributes, though great debate exists on the specific design and functionality of the system. There is no calendar for when the system will be built, and there is also not a clear funding mechanism for creating the software.

In **New York**, NYSERDA has funded two groups to develop business plans around the potential creation and design of a certificate tracking system to replace the state's current hybrid tracking approach. While it is not clear that the state will move quickly in this direction, the recent announcement of a state RPS may hasten the development of such a certificates system.

The **Western Governors Association** has also formed a steering committee to explore the design and development of a tracking system for 11 states in the Western U.S. This group has held one meeting where a decision was made to move forward with a stakeholder process to begin discussions on functional and design features of the system, costs, and contributions. This stakeholder effort has been stalled due to a lack of funds, but is expected to start up again in the Spring 2003.

In addition to California, there are three other western states that have recently passed rules that are expected to lead to the development of either a western states certificate tracking system or a loose network of state certificate tracking systems in the west. The **Nevada** Public Utility Commission recently passed a rule to establish a certificate based tracking system to verify compliance with the state's renewables portfolio standard. This rules specifies the development of a renewable certificate tracking system. **New Mexico** also passed a renewables portfolio standard that specifies renewable certificates as the method for accounting and compliance verification. **Arizona's** small, solar-focused RPS also allows for certificate trading. Finally, both **Oregon** and **Washington** have environmental disclosure labels that require some method of accounting for imports and exports into their states and have active REC trading markets. These two states have indicated a strong interest in a western certificate tracking network.

If these diverse efforts move forward, a good fraction of the country will be covered by a state or ISO operated/sanctioned certificate tracking system. In addition, interest is growing to designate a potential default certificate "Issuing Body" for generators located in states where there is no government sanctioned certificate system. While the outcome of these discussions is not yet clear, a default Issuing Body will effectively allow all renewable generators to voluntarily participate in a national REC tracking network.

Appendix B. American Association of Issuing Bodies

Introduction and Background

The U.S.EPA is funding work to formally establish a North American Association of Issuing Bodies (AAIB). The AAIB will facilitate communication among Issuing Bodies and renewable energy programs within the U.S., Canada and Mexico. In addition, the AAIB is intended to develop an framework for addressing immediate U.S. market issues relating to issuing, registering and tracking RECs transactions as well as establish property rights for RECs owners.

The AAIB development effort includes establishing a governance structure, development and negotiation of the agreements governing the interaction of the Issuing Bodies with AAIB, and with each other, to ensure compatibility of information transfer between Issuing Bodies.

Today the U.S.EPA buys RECs for its own facilities' green power commitments and uses RECs as a compliance method for participation in their Green Power Partnership Program. In addition, the U.S.EPA is interested in allowing for the potential exchange of RECs for emissions credits. As with emission credits, national coordination of RECs is required to confirm that RECs retired in one system are not also being retired in another system, a situation known also as "double-counting."

The AAIB protocols are envisioned to have sufficient flexibility to allow for individual regional and national differences while not compromising the integrity of individual programs. Two regulated RECs Issuing Bodies now exist, in Texas and New England. RECs are extensively traded in other regions of the country outside of a state or regionally supported structure. Several states are in the process of developing protocols for using RECs to satisfy renewable purchase mandates.

Establishing an AAIB will allow additional Issuing Bodies to develop accounting systems to be compatible with and serve a national RECs network and the rapidly growing RECs market. Single state or single region tracking systems are not able to definitely protect consumers from double-counting of RECs moving between states or regions without the cooperation of neighboring systems. Likewise, if RECs accounting systems are established in some areas with limited capability and are incompatible with regional RECs trading outside of regulatory mandates, the U.S. will quickly become balkanized and consumer protection will not be assured.

Importantly, the incremental cost of designing a system that will accommodate certificate markets as well as regulatory programs is negligible while the cost of trying to change a system later is significant. The AAIB provides the forum for common standards and protocols to be developed and for cooperative agreements to be formed. The AAIB is based on a model developed in Europe for linking together the RECs tracking systems of individual countries into a EU-wide tracking and trading RECs platform.

Organizational Structure

The structure recommended for the formation of an integrated network consists of three key elements:

1. American Association of Issuing Bodies (AAIB)

The intent of the AAIB is to establish a policy-neutral North American accounting system to register and track RECs ownership and retirement in wholesale markets.[29] The AAIB will lead the effort to develop some basic trade rules and minimum protocols for North America, called the 'Basic Commitment.' The Basic Commitment contains general principles that preserve transferability and accuracy of information but it does not govern how a specific Issuing Body operates. The draft Basic Commitment will be discussed and modified through a stakeholder process[30] directed by the AAIB. Ideally, each Issuing Body will incorporate these guidelines and minimum operating procedures into their own operating rules. The rules governing AAIB processes (Rules of Association) and activities will be developed and approved by the AAIB member participants.

2. Issuing Bodies

Issuing Bodies will be established for different regional domains in North America. A domain will be defined by geographical boundaries (e.g. state, power pool, country, or region) such that a renewable generating facility is assigned to one and only one domain. Each Issuing Body will develop its own operating rules consistent with the laws and renewable energy programs in its geographic domain and will agree to abide by the procedures established for cooperation with other Issuing Bodies outlined in the AAIB Basic Commitment.

The conceptual model for the AAIB contemplates two general types of Issuing Bodies: Issuing Bodies for mandatory programs and Issuing Bodies for voluntary purposes. A single Issuing Body could fill both of these roles. The Issuing Bodies for mandatory programs will most likely have some regulatory designation from the state or region where it is operating. An Issuing Body established for voluntary registration of RECs would also have to follow the guidelines of the Basic Commitment, but would not necessarily be operated by any regulatory authority. For example, a voluntary Issuing Body could be run by a private business, a non-profit, or a transmission system operator.

The chief responsibility of an Issuing Body is to ensure the accurate issuing, tracking, and retiring of RECs for any given generator and to verify the information supplied by generators. The mechanism for issuing, tracking and retiring RECs will be developed by each Issuing Body, however, they will need to meet the minimum standards in the Basic Commitment to ensure compatibility with the larger network.[31]

A second responsibility of the Issuing Body is to ensure that information is transferred and shared between Issuing Bodies when necessary and appropriate, e.g., when RECs are sold into a neighboring region with a different Issuing Body. This integrated accounting approach minimizes the opportunity for double counting RECs that are bought or sold in other regions.

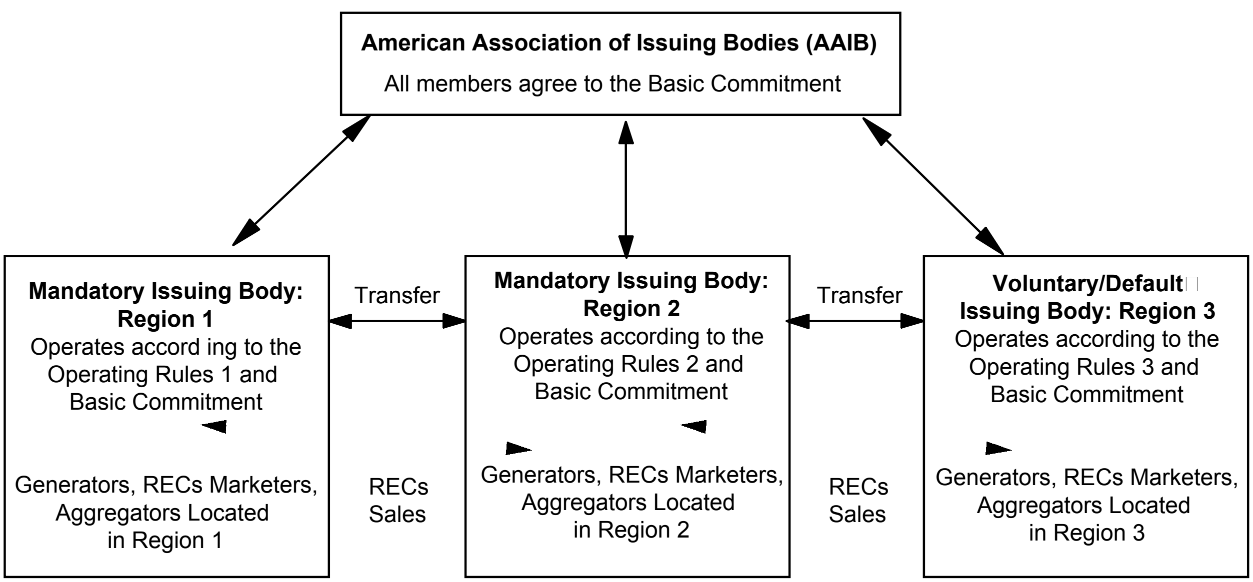
The AAIB will work through these coordination issues with stakeholders in advance of system specification finalization and investment. The goal is to make sure there is seamless coordination between Issuing Bodies so that a national network of Issuing Bodies is operational.

A third responsibility of the Issuing Bodies is to register generators and periodically verify the information provided by generators such as type of technology/fuel and operational status.

3. Market Participants

The third component of a North American RECs tracking network is market participants, including renewable energy generators, marketers, wholesale purchasers, aggregators, large end-use customers, product certifiers, and traders. These market participants must voluntarily agree to participate in such a system, unless they are located in a region where participation is mandatory, such as New England. Market participants will be involved in the development of the Basic Commitment and the relevant operating rules because of their valuable perspective on the functional requirements of a robust market.

Diagram 1: Organization Structure of a North American RECs Tracking and Verification Network



Plan and Schedule for AAIB Formation

The following outline lays out the plan and schedule for AAIB development.

Phase I: Nov 2002 – March 2003

Initial meetings with potential and emerging Issuing Bodies
Release *Basic Commitment* Draft to potential and emerging Issuing Bodies
Develop preliminary '*Rules of Association*' for AAIB
Investigate idea of generator registry
Determine candidate stakeholders, form three primary stakeholder groups

Potential Issuing Bodies, regulators
Market participants, RECs marketers
Interested stakeholders that don't fall in above two categories

Phase II: March 2003 – September 2003
Establish Steering Committee to flesh out details of *Rules of Association*
Host stakeholder meeting to review *Basic Commitment*
Revise *Basic Commitment* – send out to individual Issuing Bodies for approval

Phase III: September 2003 – December 2003
Host stakeholder meeting to introduce *Rules of Association* for AAIB members
Revise *Rules of Association* – send out for approval by potential Issuing Bodies
Develop Security/Data Integrity requirements document
Go through legal/admin work to establish AAIB as separate non-profit

Phase IV: January 2004 -
Finalize/ get approval (by Issuing Bodies) of *Basic Commitment*
Finalize/ get approval of *Rules of Engagement*
Finalize/get approval of Security/Data Integrity document
Incorporate AAIB

Appendix C. Oregon and New York RECs-based Utility Buy-through Programs

Introduction and Background

With the CPUC's suspension of customers' right to choose direct access as of September 20, 2001, no incremental customers may select green power offerings. As described in Section 1 of this report, without changes to the legislative and regulatory rules related to the Customer Credit Account, demand for account funds is likely to remain stable or decline over time. The main report discusses the options for expanding demand and impact of the Customer Credit Account, while this appendix details an alternative competitive green pricing program option in use in Oregon and New York.

In the two programs described in this appendix, competitive green power offerings are made available by and through the utility, and are invoiced through the utility bill. In Oregon, the two investor-owned utilities (IOUs) bid out for a single supplier to provide renewable energy credits (RECs) and support joint and solo program and product marketing. In this case, the RECs are rebundled with IOU provided energy and sold as "green power." In the Niagara Mohawk (NiMo) example, the utility provides access to the customers by a slate of approved RECs retailers who are selling only the renewable RECs and who market largely independently of the utility.

The context for the two programs differs considerably. In Oregon, small customers are only provided choice through their utility, whereas in New York, choice has been available by years. However, in New York, residential switching rates have varied substantially by utility service territory and in Niagara Mohawk's territory, market dynamics have not been favorable to entice competition for smaller customers. Both programs are implemented via RECs transactions, although in New York RECs are described as "conversion transactions" authorized under the state's Environmental Disclosure regulations and accounted for by the Public Service Department's Environmental Disclosure Administrator.

Summary of Findings

If considering support of mass market RECs products, it makes sense to consider a hybrid RECs/utility-sponsored green pricing option, for the following reasons:

- The benefits of competition can be captured in the absence of retail electricity competition, including:
    - Differentiation from standard utility supply is more likely in a competitive environment than under a single green pricing choice offered only by the distribution utility;
    - Competitive pressure tends to improve the value for a given price;
    - Competitive positioning increases customer awareness and increases credibility of a new product offering;

- Product differentiation will offer a portfolio of products appealing to a wider array of customers than a single offering;

- The administrative ease of RECs is meshed with the credibility of a utility green pricing program with the potential for vastly superior market penetration (and lower customer acquisition and retention costs) compared to traditional RECs products sold independently of the distribution utility; and
- Such and option can serve as either a smooth transition to the possible future reopening of direct access, or as a substitute means for effectively developing a green power market in the absence of direct access.
- This option does not require switching electric suppliers, eliminating the burden of educating customers that their reliability will not be compromised if they switch suppliers.

RECs purchases can have an equivalent environmental and electric system impact to a direct access green power offering[32], but in the mass market, suffers from the disconnect with electric service. Smaller customers perceive a RECs purchase akin to a charitable contribution rather than a product or service. As a result, there is a greater educational burden on marketers so most observers expect mass marketed RECs products to have a lower market penetration than a product offered in association with the purchase of electricity and invoiced through the electric bill. Thus, while such a program can be offered to both large and small customers, its advantages relative to the RECs market are greater for smaller customers, for whom one-on-one marketing is not used, the effort to explain tags products is not cost-effective, and the sophistication to understand tags products is less prevalent. On the other hand, a RECs product rebundled with utility electricity to form a green power product has the ease of the RECs procurement with none of the hassles of RECs mass marketing.

The Oregon Program

In July 1999 Oregon Senate Bill 1149 restructured the state's investor owned utility (IOU) electricity market. SB1149 required the state's IOUs – Portland General Electric (PGE) and PacifiCorp's Pacific Power - to offer residential and small business customers a portfolio of green power options that required inclusion of third party suppliers, and significant new renewable energy content. These choices, along with other rate options, served as an alternative to direct access for residential and small commercial customers (larger commercial and industrial customers served by IOUs were given direct access effective October 2001).

To implement the program, the PUC established a portfolio advisory committee (PAC) composed of a range of stakeholders. The PAC made recommendations to the PUC to put structure in place for implementing the program (most, but not all of which were implemented), including recommending a range of specific products. The PAC decided that in each IOU's territory, three renewable options would be offered, one by the IOU and two supplied and marketed by a third party.

The two utilities issued a competitive solicitation conforming with the PUC's rules to select the third party, with selection criteria that included price, proven experience, financial wherewithal to sign long-term contracts, and marketing capabilities. Though the solicitations were independent, both utilities selected Green Mountain Energy (GME) as their third party marketer. The program began signing up customers as of March 1, 2002.

The three offerings include:
A **Fixed Block** product consisting of 100% new wind energy offered in blocks of 100 kWh per month, supplied and marketed by the utility. In the case of Pacific Power, this offer corresponds to the "Blue Sky" program ($2.95/month for 100 kWh) that predated the other legislatively-required options (offered since 2000); PGE's Clean Wind program, also offered since 2000, charges $3.50 per 100 kWh.

A **Renewable Usage**, or blend product, representing 100% of a customer's usage. This is offered by Green Mountain Energy, who supplies RECs and the marketing for the product. It consists of 85% geothermal and 15% new wind energy.

A **Habitat** product, also offered by Green Mountain Energy, is the same as the Renewable Usage product, but also includes a donation for Salmon habitat restoration (modeled after a predecessor program, *Salmon Friendly Power*, originally offered by PGE).

The program is closed: no other competitors or offerings are envisioned to have access to the utility bill (although RECs products offered by others continue to be available in the region).

The duration of GME's contract, however, is only 22 months, through the end of 2003. The PAC is required to report back to the PUC on the program success and make additional recommendations for a solicitation for a subsequent term. The initial program appears to have been shortsighted in not addressing adequately what happened at the end of the initial term to GME or its customers, and the implications on bringing new generation on-line with such a short-term program. The next round of solicitations for 2004 and 2005 are expected to include additional terms and conditions to better address the issues of term, duration, and creating a more stable environment to support long-term green power market growth and financing of new renewables.

In this program, the DISCOs view the third party similar to an outsourced contractor for an offering. The DISCOs serve as collaborative marketers, offering "storefront marketing", with their regulated products "on the shelf" alongside those of the third-party supplier GME. This is described as akin to a supermarket in which name brands are offered alongside the store brand. The IOUs is required to market all three options equally, and the utility and GME have voluntarily decided to undertake collaborative retail marketing where possible. All three programs are featured on the web sites of each IOU[33], and are the subject of utility press releases. PGE announced recently that it is sending out mailings to every residential and small business customer beginning in late October 2002 and extending through the end of the year. Pacific

Power announced a new educational campaign with customized enrollment forms, with mailings to begin in November.[34]

The NiMo Program

The NiMo program came about as a result of pressure by renewable energy advocates during the settlement discussions over approval of a merger between National Grid U.S.A and Niagara Mohawk Power Company. It is seen as a transitional program in a direct access market that so far has failed to provide green power alternatives to customers (or for that matter, much competition for smaller customers). As a result of a Joint Proposal by a number of parties, NiMo agreed to institute a Renewable Energy Marketing and Billing Program to facilitate the sale of renewable energy in its territory.

As of September 2002, competitive "Green ESCOs" that register for the program may offer to Niagara Mohawk's generation service customers green power offerings under their own brands that are based on either (a) 100 or 200 kWh per month blocks of energy consumption, (b) percentages of energy consumption (discreet alternatives include 25%, 50% or 75% of consumption), or (c) the customer's total energy consumption. NiMo offers no renewable options under its own brand. Billing is performed through NiMo's billing system, with the renewable energy premium separately identified. The Green ESCO arranges service by streaming attributes from renewable generators located within New York to NiMo for their inclusion on mandated environmental disclosure labels via conversion transactions[35] allowed under the environmental disclosure program. The program is not available to customers that have switched suppliers. The program is open to any registered Green ESCO, and ESCOs can join the program at any time. Offerings are available to both residential and commercial customers.

The program was launched in September 2002 and three Green ESCOs have registered: Community Energy, Green Mountain Energy, and Sterling Planet. Their offerings to residential and commercial customers, respectively, were included in bill-stuffer ballots distributed in a single mailing to all customers over a single bill cycle. The types of offerings, summarized on the ballots shown below in Figures 1 and 2 (Community Energy added a 100% wind option after the ballot was distributed), were selected based on each ESCO's efforts to make their offering appealing and differentiate it relative to competitors' offerings, subject to the menu of options dictated by billing system limitations.

Figure1: September 2002 Residential Ballot

NIAGARA MOHAWK RENEWABLE ENERGY ENROLLMENT CARD

Yes, sign me up to receive renewable energy service from the supplier I have designated below. I am aware that (1) by mailing back this completed card I will have a renewable energy surcharge added to my monthly Niagara Mohawk bill; and (2) Niagara Mohawk will remain my electricity supplier and provide my customer service and emergency response.

Niagara Mohawk Account Number (from your bill)________________________________

Account holder Name ____

Address ____________________________ Daytime Phone (_____)__________

City______________________________ State_______ Zip Code_________

Check one supplier below and note option if any.

___ Community Energy 50% Wind/50% Hydro; adds 1.3 cents/kWh on all usage.

___ Green Mountain Energy 85% Hydro/15% Wind; adds 1.5 cents/kWh on all usage.

___ Sterling Planet 30% Wind/20% Hydro/50% Biomass. Select one option:

- ❏ Option 1 – Adds 1.5 cents/kWh on 50% of usage.
- ❏ Option 2 – Adds 1.5 cents/kWh on 75% of usage.
- ❏ Option 3 – Adds 1.5 cents/kWh on 100% of usage.

Niagara Mohawk
A **National Grid** Company

Figure 2: September 2002 Commercial Ballot

NIAGARA MOHAWK RENEWABLE ENERGY ENROLLMENT CARD

Yes, sign me up to receive renewable energy service from the supplier I have designated below. I am aware that (1) by mailing back this completed card I will have a renewable energy surcharge added to my monthly Niagara Mohawk bill; and (2) Niagara Mohawk will remain my electricity supplier and provide my customer service and emergency response.

Niagara Mohawk Account Number (from your bill)________________________________

Accountholder Name ____

Address ____________________________ Daytime Phone (______)____________

City ______________________________ State________ Zip Code__________

Check one supplier below and note option if any.

___ Community Energy 100% Wind. Select one option:

- ❏ Option 1 – Add _____ blocks per month at $2.00 per block (5 block minimum)
- ❏ Option 2 – Adds 2.0 cents/kWh on all usage

___ Green Mountain Energy 85% Hydro/15% Wind; adds 1.5 cents/kWh on all usage

___ Sterling Planet 30% Wind/20% Hydro/50% Biomass. Select one option:

- ❏ Option 1 – Adds 1.4 cents/kWh on 50% of usage
- ❏ Option 2 – Adds 1.4 cents/kWh on 75% of usage
- ❏ Option 3 – Adds 1.4 cents/kWh on 100% of usage
- ❏ Option 4 – Adds 1.4 cents/kWh on _____% of usage (Choose your percentage)

Niagara Mohawk
A **National Grid** Company

The primary mode of marketing under the program is the bill stuffer, to be distributed once per year. This explains the program and its voluntary nature. The ballots are returned to an independent firm hired collectively by the registered marketers. In addition to the ballot, the Green ESCOs may market renewable energy service to NiMo customers under their own brand, while referring to NiMo's role as a distribution company and generation provider for consumer education purposes. NiMo and the Green ESCOs undertake a limited degree of customer education on the program (consisting mostly of an annual bill stuffer). The Green ESCO will mail quarterly environmental disclosure labels directly to customers.

Unlike the Oregon program, the utility is not providing other marketing support, such as events or other media. Under the settlement, NiMo is only required to do one bill stuffer per year, and NiMo is only doing the minimum required of it to support the program. While additional marketers can join at any time, there is little incentive to join until the next bill stuffer ballot is being prepared.

The program is provisionally established for a term matching the term of the merger Rate Plan (there is significant uncertainty with respect to the actual duration that can be relied upon, or what would happen at the end of the program), as its purpose is to spur the development of renewable generation resources and the sale of renewable energy in NiMo's territory, and is intended at this juncture to be an evolutionary step to a fully competitive direct access market for bundled/delivered generation service. The PSC Staff will monitor the effect of the program on the development of a competitive market and may make recommendations on its continuation or dissolution.

Program Comparison – Structure and Results to Date

A comparative summary of the structure of two programs is found on the table below.

	Oregon	**Niagara Mohawk**
Genesis of program	Required under restructuring legislation	Merger settlement concession
Suppliers (open/closed)	Limited to DISCO/1 supplier selected through RFP	Open to any registered "Green ESCO"
Customer eligibility	Residential & small commercial not offered direct access	All customers of NiMo generation service
# of competitors and offers	Two suppliers in each service territory Three discrete offers (block, blend, and blend + salmon habitat)	Unlimited in principle. Currently three suppliers offering a total of 5 product choices to residential customers and 7 options for commercial customers
Role of DISCO	Distribution company and generation service provider; Competing green power supplier; Collaborative marketing for all; Billing agent (engaged participant)	Distribution company and generation service provider; Limited marketing for all; Billing agent (reluctant marketing channel, doing the minimum)

	Oregon	Niagara Mohawk
Marketing	Collaborative, "storefront" marketing of utility and 3rd party offerings on equal footing by DISCO and by 3rd party	DISCO as marketing channel through equal treatment of competitive offerings on bill stuffer ballots; plus individual efforts of Green ESCOs
Types of offerings, limitations	3 offers defined in legislation	Discrete range of offerings: 2 sizes of "blocks"; discrete percentages of usage; total consumption
Enrollments	Processed by DISCO	Processed by Green ESCOs
In place since…	March 2002	September 2002
Duration	22 months years (through 12/31/03)	Unclear what happens after duration of Merger Rate Settlement (~3 years?)

While neither program has been in place for long, early results on market penetration are very encouraging. These results are summarized in the table below:

Territory	Number of green power customers	Total eligible customers	Market penetration to date
Pacific Power	3292 as of 12/31/01 11,922 as of 10/24/02[36] (~98% residential)	415,729 residential[37]	~ 2.8% of residential
Portland General Electric	4917 as of 12/31/01 16,795 as of 10/24/02[38] (~98% residential)	637,331 residential[39]	~ 2.6% of residential
Niagara Mohawk	5682 ballots returned as of 12/20/02[40]	1.5 million total 1.4 million residential	~0.4% of residential

In Oregon, the breakdown among products is greater than 50% signing up for the "usage" product, greater than 25% for the "habitat, and less than 20% for the utilities' "block" offerings[41]. The NiMo ballot return figures do not include those customers that contacted Green ESCOs directly. This figure breaks down as follows: Community Energy, 2771; Green Mountain Energy: 245; Sterling Planet: 1155; Multiple suppliers checked: 514; None checked: 765. The presence of the last two categories indicates some degree of confusion during the initial ballot circulation; nonetheless, suppliers sending follow-ups to customers in the last two categories were able to sign up a substantial proportion of the customers in the "none" and "multiple" categories.

Analysis of Competitive Green Pricing Program Experience

Based on an assessment of the available experience, we can draw several conclusions:
First, the offerings in NiMO's competitive green pricing program, although otherwise identical to a "tag" offering (i.e. effectuated through tags), appear indistinguishable from a traditional "bundled/delivered" green power product from the customer perception, because it is channeled through the utility bill and from local sources. It is not described as a tag product; rather, it is explained as simply as possible: "you are switching your supply of energy". In fact, when Green-e was asked to certify offerings under this program, they applied their bundled certification standard rather than their tradable renewable certificate standard.

From the marketer perception, these programs have significant advantages over independent RECs offerings, primarily because of the added credibility that comes with being associated with a utility program. In a sense, because it comes through the utility bill, the customer is faced with the option to select a different product/service, rather than being asked to send money to some third party and receiving nothing tangible in return – an act that is similar to request for a charitable contribution from an unfamiliar charity, made far less appealing when made by a for-profit company.

These programs also have significant advantages over delivered/bundled direct access offerings because (a) they can be effectuated with RECs, a far lower cost and lower risk way of conducting business for the green power supplier than arranging for bundled delivered competitive generation supply, and (b) having the utility involved overcomes the fear of switching suppliers that acts as a significant barrier to green choice (or any competitive choice, for that matter).

In comparing the Oregon and NiMo approaches for potential applicability in California, a representative of Community Energy opined that, if well run, the NiMo approach is superior because (i) it offers customers more choices, (ii) it doesn't block market entry (as in Oregon, where competition is limited to a single third party); (iii) it allows for regional diversity as well as product evolution; and (iv) with more marketers, if one folds, more options are available.

However, Community Energy also observed that some specifics of the NiMo approach need not be replicated in California. First, the success of the program is a function of how willing, or how required, the DISCO is to do more than the minimum (e.g. allowing the green options to be on the bill). A more positively engaged DISCO (as is the case in Oregon) would make for better penetration, an opinion echoed by Green Mountain Energy. In addition—the fact that the customer must stay with NiMo generation service to participate prevents customers from participating while simultaneously maintaining the freedom to take the lowest-priced commodity generation offering.

A representative of Green Mountain Energy had a different perspective, finding that the higher level of engagement of the utility in the Oregon program as the primary determinant of that program's relatively greater success. They find that having the utilities do the little things that continually increase awareness – spending their own money on marketing, sending direct mail on their letterhead—will be far more important than offering a greater variety of choices. They also believe that when the program is seen by the utility as more of an outsourced function than supporting competitors, it is easier to get them to understand the degree to which they benefit from demonstrable increases in customer satisfaction. From that perspective, GME, the only common participant to both programs, expects the program results to diverge as a result of the different level of engagement by the utilities: active and enthusiastic support in Oregon, compared to disinterest in NiMo.

Two metrics to consider in comparing a competitive green pricing approach with green marketing in direct access markets, or with RECs in competitive or regulated markets, include penetration rates and customer acquisition costs. With only a few months of experience in a limited sample size, penetration statistics are certainly not conclusive. Nonetheless, the early performance of these programs compares favorably with that of other existing and past programs. For example, even at the height of California's competitive retail market, less than 2% of residential customers were being served by a green power product.[42] Similarly, in Pennsylvania, which is widely considered to be one of the most active competitive markets in the U.S., residential green power customer participation rates have failed to exceed 2%.[43]

While some of the more-than-100 regulated green pricing programs throughout the country have fared better than the competitive green power markets in California and Pennsylvania, NREL's most recent list of the "top ten" green pricing programs ranked by customer participation rates shows that the 10th best program – SMUD's Greenergy – has only achieved a 3.0% participation rate, despite having been in place since 1997.[44] Similarly, an October 2002 report on 23 green pricing programs in the Pacific Northwest shows that only 4 of these programs have exceeded a 2.8% residential participation rate (i.e., that achieved by Pacificorp and PGE since March 2002).[45] Two of these programs have been around since early 1998; the other two since early 1999.

In 2001, the PGE green pricing program was considered by the Federal government to be among the top 10 nationally; since adding multiple competing options, program signups have more than tripled in just none months for both Oregon programs. Blair Swezey of the National Renewable Energy Labs considers this program to be among the best in the nation.[46]

Customer acquisition cost data is closely held as proprietary, so little numerical data is available to support the expectation that this type of program can reach these penetrations at comparatively attractive cost. Nonetheless, the fact that RECs marketers report a preference for access to the utility bill, and that penetration rates exceed those of the best direct access green power markets, suggests that acquisition costs are indeed lower for this type of program. One expected result of lower customer acquisition costs is lower product prices, since the product price must recover acquisition-related costs amortized over the expected duration of the supplier-customer relationship.

The experience of Community Energy supports the conclusion that a competitive green pricing program may be particularly effective. Community Energy has experience in marketing RECs offerings elsewhere, including in a neighboring utility marketing the same generation to similar customer classes in partnership with the local utility (New York State Electric and Gas, NYSEG), in a circumstances where they do not have access to the utility bill. They report that their comparative results so far suggest that, all else being equal, their NiMo offering to residential customers is about twice as successful and more cost-effective than the neighboring NYSEG effort, and that the NYSEG offering to residential customers would likely be far more successful if it were allowed access to the utility bill[47]. They report that they are experiencing similar customer acquisition cost in either program, but anticipate that the costs that result from the utility-based program in NiMo territory, or their exclusive partnership with the DISCO in NYSEG territory, are so superior to the penetration and customer acquisition costs anticipated under a completely independent RECs offering that they have foregone offering such a product to residential customers.

In summary, the limited experience suggests that the market penetration will be far superior to independent RECs offerings, and customer acquisition costs will be lower than both RECs and competitive bundled product offerings. We hypothesize that this is due in large part to the added credibility gained by marketing in association with utility-supported program with regulator support (relative to RECs); the ability to make a switch without switching supplier, and the ability to use bill stuffers and ballots, which can be supplemented by green ESCO marketing.

In California's particular situation, this approach holds greater promise than a green-tag-only market for building upon the green market supported by the Customer Credit program under direct access. It can provide a mechanism for the demand that has already been tapped to be nurtured (rather than losing the direct access customers that have already been invested in over time as marketers continue to abandon a market with no hope of growth), and either serve as a smooth transition to the possible future reopening of direct access, or as a substitute means for effectively developing a green power market in the absence of direct access.

Role for CEC's Customer Credit

Neither the Oregon nor the NiMo program have been directly subsidized (although in New York, Community Energy has won a marketing grant from NYSERDA that has supported their efforts to date, and Green Mountain Energy has reportedly just been awarded a similar grant to support their future marketing efforts). For California, the question remains how the Customer Credit account might be applied to such a program.

Key design questions for program include:

How to implement the program? Does it require legislation? Would utilities voluntarily support such a program? How to get more than the minimum level of participation and support from the utilities?

The role of the utility (billing agent? Competitor? processing enrollments? "storefront market" including their own product?)

The process for selecting green marketers: competitive RFP up front, or program open to all qualified registrants?

Key design questions for Customer Credit funding include:

Who to fund? Options include (a) funding all purchases from registered green markters offering eligible products (similar to the past Customer Credit rebate), (b) funding certain marketers (akin to NYSERDA's green marketing pay-for-performance grant approach), or (c) funding joint marketing efforts and enrollment and billing system infrastructure rather than marketers or customer rebates.

How to fund? Options include (a) a per kWh or per customer incentive or rebate, akin to the past Customer Credit program in California or the current Rhode Island small customer incentive, respectively, (b) as marketing grants, or (c) payments for joint marketing efforts or infrastructure.

How much to fund? There would need to be minimum product requirements to assure credible results and equitable and credible treatment of products of different quality. GME suggested that the best usage of funds may be to support the cost of increasing and maintaining customer awareness, such as a specific and regular (bi-annual?) mailings on DISCO letterhead to customers to describe the program offerings and give them a chance to sign up; and supporting the cost of enrollment processing so that these costs need not be inefficiently duplicated by each party.

How much to fund? Unlike the previous Customer Credit program, in which substantial rebates were necessary to incent switching, it would only be necessary to partially support the green premium. The effect of any ¢/kWh credit would be to lower the price or improve the product, which would indirectly improve penetration; support for awareness and signups, as suggested in the paragraph above, would reduce the risk to marketers while more directly improving penetration.

The potential impact of customer credits include greater marketer interest; reduced customer acquisition costs; ability to price at a more sustainable rate (lowering risk of needing to amortize customer acquisition costs over uncertain customer life) than in the absence of any support; and as a result, greater penetration/market transformation.

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[1] Originally, what is now the Customer Credit Account, was one of two Subaccounts of a broader Customer-Side Account.

[2] Decline in funds demand could occur if the CEC determines that it will not pay Customer Credit Account funds to those who applied for them in 2002. Because companies contend that they priced their products to include the Customer Credit Account funds in 2002, these customers may be economically unattractive to the ESPs serving them absent such funds and the customers may be returned to utility bundled service.

[3] The New Account will fund supplemental energy payments which will be awarded to generators who sign contracts with load serving entities in compliance with RPS. The supplemental energy payments will cover the above market cost of the renewable energy procured by the LSE.

[4] The demand for funds from the New Account over the long term will depend on RPS program design, electric demand growth, market prices for renewable energy and capacity and market prices for conventional energy and capacity, among other factors.

[5] Section 383.5 (f)(2)(B) of the Public Utilities Code says in pertinent part, "Credits awarded to members of the combined class of customers, other than residential and small commercial customers, may not exceed one thousand dollars ($1,000) per customer per calendar year. In no event may more than 20 percent of the total customer

incentive funds be awarded to members of the combined class of customers other than residential and small commercial customers."

6 The original SB 90 program total funding limit for Customer Credit Subaccount funding was reached in 2001, after which demand for Account fund from large customers ceased. However, since no funds have yet been disbursed under SB 1038, demand for funds may increase from 2002 levels until the large customer demand reaches the total funding limit.

7 http://www.bayeconfor.org/pdf/CAenergyfuture.pdf

8 http://www.nopecinfo.org/

9 "Introduction to Regional Green Power Markets Reports" Presentation to the 7th National Green Power Marketing Conference, Blair Swezey, National Renewable Energy Laboratory, September 30, 2002, http://www.eren.doe.gov/greenpower/gpmc_pres/7gpmc02/swezey02.pdf

10 "National Green Power Market Update" Presentation to the 2002 Northwest Green Power Forum, Blair Swezey, National Renewable Energy Laboratory, November 19, 2002.

11 RECs are the renewable energy attributes generated along with power production from a renewable generator which may be sold separately or in combination with the commodity electricity.

12 http://www.resource-solutions.org

13 http://www.epa.gov/greenpower

14 http://www.usgbc.org

15 Not all of these states and countries use the term REC, though some do. Regardless of the name, the accounting systems function more or less the same.

16 For more information about the AAIB effort, please see Appendix B.

17 For a detailed description of the RECs systems in Texas and New England, see Appendix A.

18 For more information on RPS accounting options, see Grace, R., W. Wiser and B. Abbanet. 2000. "Massachusetts Renewable Portfolio Standard: RPS Accounting & Verification Mechanisms and Policy Coordination Report." Prepared for the Massachusetts Division of Energy Resources; and Rader, N. and S. Hempling. 2001. "The Renewables Portfolio Standard: A Practical Guide." Prepared for the National Association of Regulatory Utility Commissioners.

19 ISOs typically also use an automated system to track energy flows at the wholesale level for settlement purposes. These systems are conceptually similar to certificate tracking systems in that meter data is electronically transferred to a central database. One key difference between certificate tracking systems and energy tracking systems is that energy tracking systems track the actual flows of energy, both incoming (generation meter) and outgoing (customer meter), whereas certificate tracking systems usually track only incoming flows to determine the number of certificates that are issued. Once certificates are issued, they can be traded and transferred regardless of the actual energy flow. Instead of tracking outgoing flows by meter use, certificate systems typically retire certificates when they are used to meet customer load, to meet a regulatory requirement such as an RPS, or are exported out of the system. In this way certificate systems are able to track all certificates generated and "used" to ensure that no one certificate is "used" more than once (double-counting). Typically, a certificate is "used" when it is noted on a disclosure label or used to meet retail load, used for a regulatory purpose, such as an RPS, exported out of the system, or otherwise retired (e.g. if it expires per regulatory or legislative rules)

20 To completely assure that all registered generators are prevented from double-counting, registries of certificates must coordinate their retirement data. The effort to establish the North American Association of Issuing Bodies would provide such coordination between the TX, New England and other systems.

21 Contract path systems also suffer from a lack of clear, simple, unambiguous and fair methods of dealing with spot market or undifferentiated system power transactions.

22 For a detail description of the Oregon and New York programs, see Appendix C.

23 In order to prevent double counting of the value of the attributes underlying a REC, certifying bodies often allow a REC to be used in energy markets OR converted to pollutions offsets <u>but not for both purposes</u> unless explicitly allowed in the law or rules governing the programs.

24 This section is based on Wiser, R. and O. Langniss. 2001. "The Renewables Portfolio Standard in Texas: An Early Assessment." LBNL-49107. Berkeley, Calif.: Lawrence Berkeley National Laboratory.

25 § 39.904 of the Public Utility Regulatory Act (PURA).

26 PUC Substantive Rules §25.173 Related to Goal for Renewable Energy.

[27] Based on an assumed average capacity factor of 35%. Assuming an average annual growth in demand of 3% this translates to a renewable energy share of 2.2% by 2009.
[28] New England Power Pool Generation Information System Operating Rules.
[29] The incremental cost of establishing a framework that serves the needs of the hemisphere is very low. Both Canada and Mexico have already indicated their interest in participating sometime in the near future.
[30] The AAIB Stakeholders include existing and emerging Issuing Bodies, regulators and market participants.
[31] However, each Issuing Body (TRC tracking system) can and probably will go beyond the minimum standards to include options and services tailored to the needs of the regulators and participants in their region.
[32] When sourced from local renewables.
[33] See: Pacific Power: http://www.pacificpower.net/Navigation/Navigation1845.html
Portland General Electric: http://www.portlandgeneral.com/business/products/power_options/fixed.asp
[34] Pacificorp Press Release: "Oregonians make local renewable energy program one of fastest growing in the country" October 29, 2002
[35] Through a conversion transaction, generation attributes associated with energy sold by generators into the spot market may be transferred to an ESCO purchasing an equivalent quantity of energy from the spot market during a calendar quarter. Such spot market purchases may then take on the generator's characteristics for disclosure purposes.
[36] Source: Pacificorp Press Release: "Oregonians make local renewable energy program one of fastest growing in the country" October 29, 2002.
[37] Source: EIA summary for 2000.
[38] Source: Pacificorp Press Release: "Oregonians make local renewable energy program one of fastest growing in the country" October 29, 2002.
[39] Source: EIA summary for 2000.
[40] Source: Brent Beerley, Community Energy, figures provided to all participating Green ESCOs.
[41] Source: John Savage, Green Mountain Energy.
[42] Wiser et al. 2001. "Forecasting the Growth of Green Power Markets in the United States." http://eetd.lbl.gov/ea/EMS/reports/48611.pdf
[43] Ibid.
[44] http://www.eren.doe.gov/greenpower/topten.shtml
[45] Harris, Ned. 2002. "Power Choices III: A Survey of Retail Green Power Programs in the Pacific Northwest and Beyond." Renewables Northwest Project, August 2002. http://www.rnp.org/htmls/Powerful%20Choices%203_web.pdf
[46] Pacificorp Press Release: "Oregonians make local renewable energy program one of fastest growing in the country" October 29, 2002.
[47] For larger commercial, industrial or institutional customers, the marketing approach is entirely different, and given the ability to market *with* utility representatives in NYSEG territory, their NYSEG experience with larger customers has been superior to the NiMo offering where they have no such partnership.

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Customer Credit Account Research and Analysis
Supporting the California Energy Commission's Renewable Energy Program
Preparation of the Customer Credit Account Report for the Legislature

January 23, 2003

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Table of Contents

Executive Summary

Introduction and Background

The purpose of the California Energy Commission's Customer Credit Account has been to support customer demand for renewable energy, above and beyond that created or supported by other Accounts, with the ultimate goal being to create a self-sustaining, customer-driven market for renewable energy. Two events have changed the context within which this Account operates: the CPUC suspended direct access in September of 2001; and in September, 2002, the Governor signed SB 1078, legislation establishing the California Renewables Portfolio Standard Program (RPS) and providing a target floor for renewable power sales in California.

The questions before the Commission are whether the Customer Credit Account can still serve its purpose in its current form, if it would better serve its purpose with adjustments, or whether it should be discontinued and the funds used for other purposes. The California State Legislature, in SB 1038, specifically requires the following:

Sec. 383.5 (f)(2)(E) of the Public Utilities Code:

> By March 31, 2003, the Energy Commission shall report to the Governor and the Legislature on how to most effectively utilize the funds for customer credits, including whether, and under what conditions, the program should be continued. The report shall include an examination of trends in markets for renewable energy, including the trading of non-energy attributes, and the role of customer credits in these markets. The report will recommend an appropriate funding allocation for the customer credits and how implementation of the customer credits should be structured, if appropriate.

Summary of Findings

During the first four years of the Renewable Energy Program, customers large and small bought green power supported by Customer Credit Subaccount[1] funds. The Subaccount was successful enough to drive customers towards purchases of renewable power, and to require a 33% reduction in the credit level from 1.5 to 1 ¢/kWh.

Due to the recently added legislative restrictions on the use of the Customer Credit Account funds, without changes to the program, growth of demand for the funds is unlikely in the next two years.[2] However, if legislative restrictions are relaxed on customer and product eligibility for Customer Credit Account funds, growth in demand for funds is likely.

Today, the credit level set for the Customer Credit Account awards is equal to the payment cap from the Existing Account. The relative effectiveness of funds awarded by the Customer Credit or Existing Accounts compared to funds awarded from the New Account[3] is unknown since RPS program design is only now underway. Should the CEC wish to support customer-driven renewable energy demand using Customer Credit Account funds it would have the option of lowering the credit level.

If changes in customer or product eligibility rules are made, the Commission might also consider changing the renewable energy vintage requirements to ensure that a minimum percentage of renewable demand is directed towards renewable energy plants built or repowered after a specific date. This change would ensure that the net renewable energy mix procured by Californians would increase as a result of Customer Credit Account funding.

Customer Credit Account funds could be used to expand renewable energy purchases beyond the goals set by the California RPS, but this will not occur without legislative and program rule changes. If demand for funds does not grow, the remaining Customer Credit Account funds can be reallocated to another Account as needed. Since fund disbursement from the New Account will grow gradually, and over half of the total Renewable Energy Program funds collected annually go to that account, the New Account is not expected to need additional funds in the near term.[4] That fact leaves the CEC with the option of testing changes in the Customer Credit Account and allocating any excess funds from the Customer Credit Account to the New or Emerging Accounts at a later time. This report discusses several options for the redirection of Customer Credit Account funds.

Report Scope

In support of the development of the CEC's report to the Legislature on the Customer Credit Account, the XENERGY team was asked to provide research and analysis in two specific areas:

California's Direct Access Market

Because the suspension of direct access directly impacts the Customer Credit Account, the XENERGY team examined recent events affecting the drivers of direct assess in the state. This section of the report reviews the outcome of recent regulatory events and addresses how ongoing proceedings could affect direct access and demand for Customer Credit Account funds. This section also reviews how relaxing customer and product eligibility rules, within the current direct access market, could change demand for Customer Credit Account funds. One option which would require both legislative and regulatory changes would be to offer RECs or green power through utilities as an add-on option for bundled customers. Such options are now offered through programs in Oregon and New York which we profile in detail in Appendix C.

U.S. Renewable Energy Certificates Markets

The XENERGY team reviewed the commercial success and certification and verification infrastructure for renewable energy certificates (RECs) markets in the U.S. This section of the report includes a survey of wholesale and retail RECs markets in the U.S. and provides insight into how RECs retailers would respond if RECs were made eligible for Customer Credit Account funds. In addition, because a credible retail RECs market is predicated on a solid wholesale RECs infrastructure, we provide additional information about the formal RECs verification systems established in Texas and New England in Appendix A. Because RECs verification across market areas requires coordination between registries, in Appendix B we also include a discussion of current effort to establish a national RECs infrastructure — the American

Association of Issuing Bodies (AAIB) — to allow a liquid, easily verifiable wholesale RECs trading market to grow.

Section 1. California's Direct Access Market

Introduction and Background

SB 1038 allocates 10% of the funds collected for the Renewable Energy Program to the Customer Credit Account, supporting customer-driven demand for renewable energy. The Customer Credit Account is intended to layer support of new and existing renewable energy generation in California on top of the support from the Existing and New Accounts. During the first four years of the Renewable Energy Program, the popularity of the customer credit program caused the Energy Commission to reduce the customer credit level by a third, from the legislated cap of 1.5 c/kWh to 1 c/kWh. SB 1038 limits Customer Credit Account eligibility to customers who had contracted for direct access on or before September 20, 2001, the date direct access was suspended by the CPUC.

During 2002, the Customer Credit Account received requests for funds of roughly $5 million, or about 35% of the annual allocation to the Account of $13.5 million. Existing direct access customers represent about 14% of load in the state served by the investor owned utilities, but the vast majority of this load is ineligible for Customer Credit Account funds due to the limits on total funding to large commercial and industrial customers. Demand on the Account could increase substantially, despite the suspension of direct access contracting, if limits on large customer access to the Customer Credit Account were adjusted or removed. In fact, even with the existing limits per customer limits on the non-residential, non-small commercial customers, given the size of direct access load that meets the contracting deadline in statute, the total annual demand on the Customer Credit Account could exceed the 10% Account allocation set by SB 1038 if the total funding restriction for this customer class were removed.[5]

With the change in the market structure in California, suspension of direct access, and the advent of the California Renewables Portfolio Standard (RPS) Program, the legislature has asked for a reevaluation of the customer credit program. The questions that arise are whether the Customer Credit Account can still serve its purpose in its current form, if it would better serve its purpose with adjustments, or whether it should be discontinued and the funds used for other purposes.

Section 383.5 (f)(2)(E) of the Public Utilities Code:

> By March 31, 2003, the Energy Commission shall report to the Governor and the Legislature on how to most effectively utilize the funds for customer credits, including whether, and under what conditions, the program should be continued. The report shall include an examination of trends in markets for renewable energy, including the trading of nonenergy attributes, and the role of customer credits in these markets. The report will recommend an appropriate funding allocation for the customer credits and how implementation of the customer credits should be structured, if appropriate.

We begin evaluation of the effective uses of Renewable Energy Program funds by looking at the status and drivers of the direct access market in California to assess the range of demand for Customer Credit Account funds given the existing set of direct access customers and the rules that govern them. We then turn to potential adjustments in eligibility for the Customer Credit Account and the impact of those changes on demand for the Account funds. The adjustments considered take into account the national trends in the retail, customer-driven renewable energy marketplace. Finally, we consider the other demands on funds for the Renewable Energy Program and where these funds might be used if the Customer Credit Account were discontinued.

Direct Access Market Status

ABX1-1, which became effective February 1, 2001, required the CPUC to suspend direct access but granted the commission discretion as to when the suspension would occur.

Section 80110 of the Water Code:

> After the passage of such period of time after the effective date of this section as shall be determined by the commission, the right of retail end use customers pursuant to Article 6 (commencing with Section 360) of Chapter 2.3 of Part 1 of Division 1 of the Public Utilities Code to acquire service from other providers shall be suspended until the department no longer supplies power hereunder.

The law identified an end point for direct access suspension indicating that the legislature intended to allow direct access contracting to eventually resume.

The CPUC exercised their authority by suspending customers' right to enter into new direct access contracts as of September 20, 2001 by interim order D.01-09-060 and left open the possibility of ordering an earlier suspension date. On March 21, 2002, the CPUC issued D.02-03-055, confirming that the date of suspension would remain September 20, 2001. The March decision discussed the potential application of an exit fee or direct access surcharge for customers who entered direct access contracts prior to the suspension date but set aside the specific determination of such a fee to a later date. In D.02-03-055, the CPUC also set forth some of the key rules for the direct access suspension standstill policy: direct access contract assignments and renewals are allowed, as are customer moves, but add-ons of new load under existing contracts are not.

The CPUC has taken action on several other items that affect direct access customers. A series of decisions were rendered in late 2002 that affect the level of direct access customer surcharges, including:

- D.02-07-032 SCE's Historical Procurement Charge Interim Decision
- D.02-11-074 (replacing D.02-10-063) DWR Bond Surcharge Calculation Methodology Decision

- D.02-11-022 Direct Access Cost Responsibility Surcharge (Exit Fee) Decision

The Exit Fee Decision established a rate cap for direct access customers inclusive of all charges, including SCE's Historical Procurement Charge and the Bond Surcharge. Initially, that cap has been set at 2.7 c/kWh. The commission expects to reevaluate the level of the cap by July 1, 2003.

Consistent with the statutory intent that contracting for direct access be suspended rather than undermine customer choices made prior to suspension, the CPUC has consistently expressed its view that the direct access market should be maintained and remain viable. Examples of the CPUC's support for retaining a viable direct access market follow:

D.02-03-055 p.16

> We agree with ORA and CMTA/CLECA that there are significant risks associated with an earlier suspension date as well as benefits associated with retaining a viable direct access market.

D.02-11-022 p. 109

> We observed that the "pancaking" of surcharges in different proceedings may lead to DA contracts becoming uneconomic. Yet, we have also set forth our policy in D.02-03-055 that there is value in maintaining the DA market. To guard against DA contracts becoming uneconomic, we stated in D.02-07-032 that "there should be a cap on the total surcharge levels imposed on DA customers (including the impact of any changes to PX credits)."

In order for contracting for direct access to reopen in California, legislation is likely required. Direct access stakeholders have begun to seek legislative action now that the utilities have resumed electricity procurement, the electricity bonds have been sold and exit fees have been set.

Drivers of Demand on the Customer Credit Account

SB 1038 limits eligibility for customer credits as follows:

Section 383.5 (f)(1) of the Public Utilities Code:

> Ten percent of the funds collected pursuant to paragraph (6) of subdivision (c) of Section 381 shall be used to provide customer credits to customers that entered into a direct transaction on or before September 20, 2001, for purchases of electricity produced by registered in-state renewable electricity generating facilities.

This language limits customer eligibility to those with a valid direct access contract prior to the suspension date and who purchase eligible renewable power. Because direct access load is about 14% of load in the state served by the investor owned utilities, demand could increase for Customer Credit Account funds in 2003 subject to the limits in the bill:

383.5 (f)(2)(B) Public Utilities Code

> … Credits awarded to members of the combined class of customers, other than residential and small commercial customers, may not exceed one thousand dollars ($1,000) per customer per calendar year. In no event may more than 20 percent of the total customer incentive funds be awarded to members of the combined class of customers other than residential and small commercial customers.

Before direct access contracting is reinstated, the number of customers and amount of load on direct access will be driven by the economics of the direct access market and other market rules. In all cases, the CPUC has been clear that the goal is to cap the load served via direct access while contracting is suspended. Thus, only reductions in total direct access load potentially eligible for customer credits will occur prior to suspension being lifted.

The extent to which reductions in direct access load will occur are not predictable because the basic economics of direct access remain unclear. Although the CPUC has ordered a cap imposed on exit fees, the level of the cap will be reevaluated by July 1, 2003 and could increase. Customers have argued that even the current cap level will make some contracts uneconomic and drive customers to return to bundled utility service. In addition, the procedures for calculating the credit direct access customers receive from the utility for avoiding generation procurement is under review, which could have a positive or negative impact on the economics of direct access customers. Changes to programs and tariffs under proceedings such as the demand response proceeding (R. 02-06-001) could cause changes to the competitive landscape that draw direct access customers back to utility bundled service.

Direct access eligibility rules related to the suspension of contracting also remain contested. For example, a decline in total direct access load is guaranteed to the extent that, over time, some customers will move out of a service territory, close a business location or otherwise cease service. However, some parties are now in the process of attempting to modify commission decisions to allow a customer with a set of locations to replace direct access load that ceases service with load from another location without direct access service. Also, the implications of California's Renewables Portfolio Standard Program on direct access customers are unknown because the proceeding for that purpose has just been initiated.

For all of these reasons, it is impossible to predict the size of the direct access load reduction of any of these drivers due to the confidential nature of direct access contracts. In one scenario, demand for customer credit funds could dwindle to zero if existing eligible customers are driven back to utility bundled service by the impacts of exit fees or other rules. In another scenario, the existing demands on funds could remain, with increasing demands from the existing non-residential, non-small commercial customers up to the limits set in SB 1038.[6]

When suspension of direct access is lifted, SB 1038 will continue to limit customer credits to direct access customers with contracts prior to the suspension date. Thus, changes in section 383.5 of the Public Utility Code would be required to expand eligibility to other direct access customers when direct access is reinstated.

Customer Eligibility Adjustments

Adjustments to eligibility requirements for the Customer Credit Account funds could increase demand for the funds and thus increase renewable generation above and beyond the 20% goal set by the California RPS. Funding eligibility might be expanded by customer category or product category. We address the customer eligibility issues first and the product eligibility next.

Expansion of the eligibility requirements to a broader group of customers may be driven by several factors including revocation of direct access suspension, implementation of AB 117, the Community Aggregation bill signed by the Governor in 2002, or potentially by new legislation reopening direct access in full or partial form.

However, before legislative action is taken, the CPUC will set the stage for the potential size and success of the competitive retail market in its procurement proceeding, R.01-10-024, where it is addressing the utilities' long-term procurement plans. As with similar proceedings in other states, utility procurement for default service customers (all those who are not served by a competitive supplier) is dynamically intertwined with the potential for robust retail electricity choice. Particularly in California, the scale and length of DWR and other long-term contracts will dictate the availability of load reductions to utility bundled service without the imposition of additional exit fees to collect stranded costs. To the extent that "free" load reductions are limited, energy efficiency, demand response, distributed generation and direct access effectively compete for expansion opportunities. Thus, the potential for growth in demand for Customer Credit Account funds will be driven, in part, by the decisions in the procurement proceeding.

Customer representatives are pushing for more choices. The Bay Area Economic Forum released a report in November 2002, "California's Energy Future: A Framework for an Integrated Power Policy,"[7] that identifies the spectrum of options available for the next vision of California's electric public policy. The Forum, a partnership of the Association of Bay Area Governments and the Bay Area Council, recommends that customer choice be reintroduced and encouraged in California. The report offers a variety of alternatives for retail electricity choice that are being used in other markets, from bidding out default service to a core/non-core split for choice eligibility.

In either the case where large customers are offered choice again, but small customers are not, or the current situation where larger customers have access to funds but are limited in total funding and funds per customer per year, the demand for customer credit funds could increase further if the caps are relaxed on annual funding per large customer and the limit on the total funds going to the large customer category.

The Community Aggregation bill, AB 117, has spurred interest from small customer advocates for more choices. The Customer Credit Account was set up to focus resources on small customers, and with the implementation of AB 117, growth in demand for customer credit funds could be strong, should adjustments be made in eligibility rules to allow it. In Ohio, the Northeast Ohio Public Energy Council[8], an aggregation comprising about 400,000 residential customers, competitively procured electric service and is being served with cleaner energy blend than the default service offered by the utility. The Customer Credit Account could serve as a stimulus for Community Aggregation around renewable energy choices. However, because SB 1038 limits eligibility for Customer Credit Account funds to those with contracts signed before the suspension of direct access, this legislative provision would have to be relaxed or removed in order for community aggregation contracts to be supported by Customer Credit Account funds.

As evidenced in Texas, the competitive retail renewable market and the policy-driven wholesale renewable market are symbiotic. Wind plants are being built faster than required by the RPS with near-term, shorter duration contracts from competitive suppliers for wind attributes (RECs) supporting the gap. Green Mountain Energy Company reports that its customers support 150 MW of wind in Texas.

The legislature will determine whether and when to adjust statutory eligibility requirements for customer credits. Adjustments in customer eligibility driven by changes in direct access rules or law could quickly and sharply increase demand for customer credit funds.

Product Eligibility Adjustments

Due in large part to the success of competitive renewable energy retailing in California, supported by the Customer Credit Account, customer-driven demand for renewable energy has spread widely in the past three years in the United States. The National Renewable Energy Laboratory (NREL) concludes that competitive retail renewable energy products are available in 8 states, regulated green pricing programs are available in about 200 utility service territories in 32 states and nearly 40% of U.S. customers now have access to a green power product from a competitive retail supplier or through a utility green pricing program.[9] NREL calculates that 400,000 customers are now purchasing green power, and more than 1,000 MW of new renewable power plants are installed or planned to serve the combined customer-driven demand in the three primary markets: the competitive retail market, the regulated utility green-pricing market, and the national retail renewable energy certificates (RECs) market.[10] Customers in all states have access to retail RECs[11] from about a dozen companies.

California launched this explosion in 1998 with competitive renewable energy products. Success with the competitive market and with early utility green pricing programs, like that of the Sacramento Municipal Utility District, led to the proliferation of green pricing programs in regulated markets. In just the last two years, the RECs market has exploded. As explained more fully in the next section, the wholesale renewable energy market now functions almost exclusively on a RECs basis.

The retail market has found that larger customers, commercial, industrial and institutional, take the time to become educated about renewable energy and have become comfortable buying a RECs product unbundled from accompanying electricity. A bundled renewable power product is usually composed of RECs matched with real-time, full-requirements commodity electricity. RECs retailers report that once a customer understands that RECs can be matched with any electricity source to create "green power" they are likely to be willing to consider purchasing RECs without making any changes to their electricity service.

Another factor in the growth of retail RECs is the very recent set of programs and certification opportunities that welcome RECs as a legitimate way to support renewable energy and provide positive environmental benefits. The Center for Resource Solutions, an independent not-for-profit, which certifies green power products, now certifies RECs.[12] The EPA's Green Power Partnership allows Partners to qualify by purchasing green power products or RECs products.[13] The U.S. Green Building Council, which administers the LEED™ rating system, has recently revised its green power eligibility rules to allow RECs to qualify for 1 of 17 energy related rating credits.[14]

Today, California customers buy retail RECs products from a variety of vendors in small volumes. Because RECs are sold separately from commodity electricity, a customer can remain with bundled utility service and still buy RECs to support renewable energy. Thus, expanding the products eligible for Customer Credit Account funds to include RECs would not require changes to direct access rules, but could increase California's demand for renewable energy.

Research performed for the Energy Commission indicated that RECs vendors have shied away from California due to regulatory uncertainty in the electricity market generally, as well as uncertainty with rules specific to renewable energy markets. However, all contacted RECs vendors expressed an interest in the California market if the regulatory issues were resolved and customer credit funds were made available to support RECs sales in California. One of the key regulatory issues for tag vendors is the development and implementation of a registry and accounting systems for renewable energy in California.

RECs are also being sold through regulated utilities by competitive suppliers in programs in Oregon and New York. California's legislation does not contemplate this kind of a program, but it is possible that Customer Credit Account funds could be used to support this style of a program, increasing customer-driven demand for renewable procurement beyond RPS goals, without resumption of direct access. The Oregon and Niagara Mohawk programs are discussed in detail in Appendix C.

Other Renewable Energy Program Funding Demands

The California RPS holds great promise for more than doubling the renewable energy procurement in the state. The sufficiency of funds in the New Account for supplemental energy payments to support procurement of renewable energy to meet the 20% goal is unknown. Scenarios evaluated by the Energy Commission show that funding sufficiency is very sensitive to the supplemental energy payment level among other factors. Plausible scenarios show that the New Account alone will sufficiently fund the California RPS goal of 20% renewable energy, and other plausible scenarios show that total funds from all Accounts are insufficient to meet the 20% goal. Assessing the relative probability of scenarios will depend on the methodology selected to determine the SB 1078 market price, the timing of PG&E and SCE's return to credit-worthy status, the procurement plans adopted for the utilities by the CPUC, growth in electricity demand, and the evolution of renewable and conventional wholesale power markets generally.

The intent of the legislature was to set up a portfolio of funding methods for existing, new and emerging renewable energy technologies. The Customer Credit Account has been a successful element of that strategy. Demands for increased funds may occur in the New Account, but the level of that demand cannot be forecast until the rules are developed for RPS procurement. The Emerging Account has had demand significantly greater than allocation of funds for the last two years. The Existing Account, representing 20% of the total funds, has had significantly lower demand than funds allocation in the last two years, a situation expected to continue.

The Energy Commission must decide if and when to transfer funds from Accounts with lower demand to Accounts with higher demand. At this time we cannot predict whether or when the New Account will need additional funding, whereas the Emerging Account has high probability immediate needs. Funding requests for the Customer Credit Account are currently at about 35% of the allocation whereas the Existing Account will likely have very little funding demand and double the allocation of funds compared to the Customer Credit Account. Thus, if funds are needed for reallocation to the Emerging or New Accounts in the near term, the Existing Account funds are another potential funding source.

Beyond demands for funding from the direct users of the Accounts, the California RPS creates a need for funds to support the development, construction and operation of an accounting system for which the Energy Commission is responsible. An option for use of reallocated funds from the Customer Credit or Existing Accounts would be to support the New Account and RPS by creating an accounting system that maximizes RPS compliance flexibility and minimizes compliance costs.

Options for Effective Use of the Customer Credit Account

Historically, the Customer Credit Subaccount successfully supported renewable energy demand. During the first phase of the program, the customer credit level dropped by a third from the statutory cap of 1.5 c/kWh to 1 c/kWh reflecting the increase in demand for the funds. At 1 c/kWh, the Customer Credit Account credit level is equal to the Existing Account payment cap. The CEC will not know the level of supplemental energy payments from the New Account for renewable energy procurement in compliance with the California RPS until rules are established and procurement begins. The CEC has the flexibility to reduce the customer credit level further based on increased demand for funds or to match the level of supplemental energy payments.

Options available to the CEC and legislature to effectively use customer credit funds include the following:

- Support existing, eligible direct access customers at the current credit level, equal to the payment cap on the existing account, up to the legislative funding limits;

- Relax either or both the per customer and aggregate funding limits for large customers to expand demand for renewable energy among existing, eligible direct access customers;
- Adjust customer eligibility rules to include either or both community aggregation customers and new direct access customers after direct access is reinstated;
- Adjust product eligibility rules to include retail RECs sold directly to customers or through utility programs;
- Reallocate excess Customer Credit Account funds to the New or Emerging Accounts immediately or on an as needed basis;
- Reallocate a portion of the funds to develop, construct and operate the RPS accounting system required of the Energy Commission.

Section 2. U.S. Renewable Energy Certificates Markets

Introduction and Background

Renewable Energy Credits (RECs) are used throughout the world for two primary purposes: 1) as an accounting mechanism to verify compliance with a renewable energy or air quality mandates; and 2) as a commercial mechanism that allows more liquid trading of renewable energy attributes separate from the commodity energy generated by a renewable power plant. In both cases, a REC creates a unique and easily verifiable claim to renewable generation attributes. For this reason, a substantial amount of the wholesale renewable energy sold today from new renewable energy facilities in the U.S. involves REC transactions.

The Energy Commission is considering developing a RECs-based accounting system required by SB 1078 to track compliance with California's RPS. In addition, in evaluating the options available to most effectively use funds in the Customer Credit Account, the Energy Commission is assessing the value of expanding product eligibility to retail RECs, which can be sold to customers to support renewable energy without requiring a change in electricity suppliers.

RECs represent the separable bundle of non-energy attributes (environmental, economic and social) associated with the generation of renewable electricity. RECs are sometimes also referred to as RECss, green tickets, and tradable renewable certificates. A REC is created for every unit of renewable electricity output (usually denominated in MWh), and no more than one REC can be created for any given unit of generation. In this report, we use the term REC in its broadest definition to mean simply the attributes of a given unit of renewable generation, separated from the underlying electrical energy.

The rapid adoption of RECs for regulatory and commercial purposes stems, in part, from the mismatch of renewable generation and consumption profiles. Because most renewable energy requirements (and customer demands for renewable energy) require an annual compliance demonstration, a minute-by-minute match of renewable generation and consumption is unnecessary. For their part, RECs provide a flexible mechanism for intra-year banking of renewable generation attributes that compensates for the fact that renewable energy cannot be easily stored to match a specific customers' load and that some renewable resources are intermittent. In some cases, inter-year banking of RECs is allowed, and RECs make such banking easy to track.

RECs are increasingly used in both retail and wholesale electricity markets by generators, wholesalers, brokers, agents, retailers and customers as a commercial accounting mechanism for renewable energy, and by environmental and utility regulators to demonstrate compliance with state renewable energy purchase mandates, verification of environmental claims, and other energy and environmental obligations. In particular, several U.S. states, Europe and Australia all use RECs as the accounting tool to measure and track renewable generation.[15] New uses for

RECs are continually emerging as electricity markets evolve and as businesses create new ways to sell and finance renewable projects. For example, unbundled RECs are increasingly being sold directly to customers to satisfy "green power" demands.

RECs can be generated and claimed by any renewable generator inside or outside of an official system. A central registry, or "Issuing Body" ideally generates official certificates, electronically or on paper, assigning property rights to the generator for the RECs. Because RECs are intangible, a central registry allows independent verification of meter data from facilities to confirm electricity and thus certificate generation and creates a unique identification code for each certificate allowing for verification that certificates are not being sold in multiple locations. This registry, or another entity, may serve as a repository of "retired" or "consumed" RECs as well as a clearinghouse or trading platform for RECs purchases and sales.

The U.S.EPA is funding work to formally establishing a North American Association of Issuing Bodies, including establishing a governance structure for the AAIB, development and negotiation of the agreements governing the interaction of the Issuing Bodies with AAIB and with each other to ensure compatibility of information transfer between Issuing Bodies.[16] Such coordination is required to independently confirm that RECs retired in one system are not also being retired in another system. The Energy Commission is participating in the Western Governors' Association process to establish a comprehensive Western RECs system to match the WECC electricity market territory.

RECs as a Commercial Vehicle in Renewable Wholesale and Retail Markets

RECs are a convention in the renewable wholesale and retail markets. The vast majority of wholesale renewable transactions today include a RECs transaction. All registered wholesale renewable transactions in Texas and New England employ RECs, as are the majority of wholesale renewable transactions in the Mid-Atlantic and the Pacific Northwest regions, which have been dominated by wholesale tag players like Community Energy, PacifiCorp Power Marketing and Bonneville Environmental Foundation. The Center for Resource Solutions, an independent not-for-profit, which certifies green power products, now also certifies RECs.

In California, RECs are in commercial use and also have a statutory basis. SB 1038 specifically identifies that the environmental attributes for two net-metered renewable projects, their RECs, remain the property of the facility owner. The DWR contracts signed with wind generators specifically excluded the sale of RECs to DWR. On the retail side, the APX has operated a "green ticket" exchange in California for the last four years, serving the direct access market. Businesses with locations in California have become members of EPA's Green Power Partnership by purchase RECs. Even California state buildings seeking LEED™ certification now have the opportunity to qualify for 1 out of 17 possible energy-related credits buy purchasing RECs.

Today, California customers buy retail RECs from a variety of vendors in small volumes. Because RECs are sold separately from commodity electricity, a customer can remain with bundled utility service and still buy RECs to support renewable energy. Thus, should the legislature decide to expand the products eligible for Customer Credit Account funds to include RECs, no changes would be required to direct access rules.

Research performed for the Energy Commission indicated that REC vendors have shied away from California due to regulatory uncertainty in the electricity market generally, as well as uncertainty with rules specific to renewable energy markets. However, all contacted REC vendors expressed an interest in the California market if the regulatory issues were resolved and customer credit funds were made available to support REC sales in California. One of the key regulatory issues for REC vendors is the development and implementation of a registry and accounting systems for renewable energy in California.

RECs as an Accounting Mechanism for Renewable Transactions

RECs are used as an accounting mechanism for governments implementing RPS policies. There are presently eight states that are using or that plan to use RECs for RPS compliance purposes: Arizona, Nevada, Texas, Massachusetts, Maine, Connecticut, New Jersey, and Wisconsin. The Texas and New England systems are currently the most well-developed and advanced of these systems.[17] Other countries that have developed RPS policies have universally turned to REC systems to monitor and verify compliance with those policies, e.g., Australia, the United Kingdom, Italy, and Belgium.

Though not used for RPS compliance purposes, the California Energy Commission was the first regulatory agency in the U.S. that recognized RECs by allowing their use for verification purposes for the Renewable Energy Program's Customer Credit Account. The Automated Power Exchange's (APX) California RECs market has been in operation for four years and has been a one-stop-shop for retailers or customers looking to purchase RECs and generators or wholesalers seeking to sell them.

The concept of RECs has recently been adapted in the Northeast to provide an accounting mechanism for all forms of electricity. In this context, market participants use the terms 'generation attributes,' or simply 'certificates,' to refer to the attributes of any form of electric generation, e.g., coal certificates, nuclear certificates or natural gas certificates. A full generation certificates system such as the one in place in New England affords utility and environmental regulators the ability to easily and effectively monitor compliance with RPS requirements, generate fuel source and emissions disclosure labels for electricity products, and verify compliance towards air pollutant emissions requirements.

REC systems issue a unique certificate for every unit of renewable electricity generation (typically, each MWh). By then tracking that certificate through intermediate transactions from the renewable generator to the load serving entity (LSE), state regulators can easily determine whether a load serving entity has met its renewable energy mandate. RECs can be used for accounting purposes whether RECs are transacted separately from or bundled with electricity, though as discussed later in this report, a principal benefit of RECs comes in their ability to be transacted separately from electricity.

RPS Accounting Options

SB 1078 gives the Energy Commission the authority and responsibility to design and develop an accounting system to track RPS compliance, to prevent double-counting of renewable energy output, and to allow for the verification of product claims inside or outside the state:

> 399.13. The Energy Commission shall do all of the following:
> (b) Design and implement an accounting system to verify compliance with the renewables portfolio standard by retail sellers, to ensure that renewable energy output is counted only once for the purpose of meeting the renewables portfolio standard of this state or any other state, and for verifying retail product claims in this state or any other state. In establishing the guidelines governing this system, the Energy Commission shall collect data from electricity market participants that it deems necessary to verify compliance of retail sellers, in accordance with the requirements of this article and the California Public Records Act (Chapter 3.5 (commencing with Section 6250) of Division 7 of Title 1 of the Government Code). In seeking data from electrical corporations, the Energy Commission shall request data from the commission. The commission shall collect data from electrical corporations and remit the data to the Energy Commission within 90 days of the request.

Though REC systems, or certificates systems more generally, are increasingly the tool of choice in accounting for RPS requirements, alternatively a contract-path system, can be employed. Below, we summarize these two basic accounting systems, and describe the general advantages and disadvantages of each.[18]

Contract Path Systems

Contract path systems use bilateral contracts and receipts (a "paper trail"), usually going back to the generator, to verify the quantity and characteristics of the generation attributes purchased or sold. Contract path tracking systems are typically associated with transactions where the energy and attributes remain bundled together.

Generally, a company's product or portfolio mix is considered to be a sum of its electricity contracts. Nearly all contract path systems are characterized by a third party review, usually an auditor, of sworn attestations, contract receipts and other proof of generation and transfer of ownership (e.g. between a generator, intermediary, or final marketer). Meter data is sometimes used to verify such attestations and contracts. This is the method that has been used by the Energy Commission to verify Customer Credit Subaccount fund distributions and the power source disclosure requirements of SB1305, though the Energy Commission has also allowed the use of RECs in certain circumstances.

Certificate-Based Systems

In principal, contract-path tracking could also be used to verify the sale of RECs. However, using a paper trail of REC purchase and sales contracts, after the fact, is a more cumbersome and less secure way of verifying REC transactions than using a fully functional electronic REC system.

Two key differentiating characteristics of certificate systems from contract path systems are therefore (1) that the mere possession of a REC is proof of ownership of the underlying generation attributes, and (2) that certificates are tracked electronically from "cradle to grave." Unlike under contract path systems, regulators therefore need not use a paper trail to track RECs and manual review of contracts is unnecessary in establishing REC ownership.

Under certificate tracking systems, RECs are electronically issued for each unit of recorded renewable generation. Individual RECs are identified by a unique serial number. REC ownership is tracked electronically, and all REC trades are recorded in electronic accounts (much like electronic bank accounts). At the end of an RPS compliance period, regulators can easily check the REC accounts of electricity suppliers to determine if those suppliers own sufficient RECs to meet their RPS requirements.

Certificate-based systems also generally allow RECs to be "unbundled" from the underlying electricity and sold separately from electricity. Thus, another defining characteristic of certificate tracking systems is the unbundling of electricity attributes from energy flow.[19] The RECs can then be freely traded in secondary markets

Advantages of Certificate-Based Systems

Certificate or REC based systems are now widely considered superior to contract-path tracking, and are in increasing use worldwide. Some of the specific advantages of certificate systems are highlighted below.

Ease of Administration

Certificate-based systems are easy to administer and use because they track RECs with simple automated systems. Unique REC ownership is easily determined by a review of the electronic accounts. Unlike contract path systems, there is no need to follow a daisy chain of electricity contracts to determine renewable energy attribute ownership. Reliance on attestations and a review of paper contracts is similarly unnecessary. Though certificate systems may be somewhat more costly to establish initially, the ongoing costs and staff requirements are low. As the number of market participants increases, the ease of administering a REC system becomes all the more important. Based on the Energy Commission experience administering and operating a contract path accounting system for the Customer Credit Subaccount and the Environmental

Disclosure Program, we believe it would be challenging to administer a contract path verification system for the RPS, especially considering the fact that the RPS applies to both IOUs and ESPs.

Banking and Borrowing for Compliance Flexibility

SB 1078 requires that the CPUC adopt flexible compliance rules for the RPS "including, but not limited to, permitting electrical corporations to apply excess procurement in one year to subsequent years or inadequate procurement in one year to no more than the following three years." In other jurisdictions, such flexibility mechanisms are sometimes referred to as "forward banking" and "deficit borrowing," respectively. Certificate-based systems can then be designed to easily accommodate the desired flexibility mechanisms. For example, a RECs system could establish compliance subaccounts for various years, and allowing an IOU to transfer certificates between subaccounts, or to borrow from future subaccounts. Borrowing would occur by increasing the compliance requirements in a future compliance period.

Baseline Monitoring and Verification

SB 1078 requires that the CPUC establish "an initial baseline for each electrical corporation based on the actual percentage of retail sales procured from eligible renewable energy resources in 2001, and, to the extent applicable, adjusted going forward pursuant to subdivision (a) of Section 399.12." RECs can include information on the age of the generation facility and its eligibility for meeting the baseline quantity or for meeting the incremental RPS commitments. Once the REC is identified as counting toward the baseline quantity of an electrical corporation, it could automatically be credited to the IOUs "baseline" subaccount. Facilities that add incremental new generation to an existing facility could also be accommodated such that a percentage of the output is marked as baseline and the remainder is marked as incremental. Alternatively, within a single year, all certificates owned by an electrical corporation up to the pre-determined baseline quantity could be marked as baseline, with all RECs thereafter during the year marked as incremental.

Assurance of No Double Counting

An RPS accounting system must be able to assure that renewable generation attributes are not "double counted" or otherwise used impermissibly. An electronically based REC system all but assures that double counting of tags from registered generators does not occur.[20] Only REC ownership allows a purchaser to claim the generation attributes, and only a single REC is generated for every unit of electricity generation. Under a contract-path tracking system, on the other hand, regulators must rely on paper contracts, attestations, and after-the-fact reviews. Assurance of double counting cannot be provided as firmly and securely as under a certificate system. For example, under a contract path system a utility may be able to demonstrate that they have purchased renewable electricity through a contract showing, but that same IOU would not be able to uniquely prove that no other supplier has asserted the same claim.[21]

Cost Minimization

RECs are commonly used in wholesale markets to facilitate renewable electricity trading. This is because RECs offer a uniquely flexible compliance tool for utilities and ESPs. For example, if renewable generation is most cost-effectively developed in Northern California, RECs allow renewable development to occur in the Northern part of the state, with RECs sold to utilities or ESPs throughout the entire state without the need for direct electricity transmission to those areas. This ensures that renewables development will occur in the lowest cost areas, and will not be "forced" in higher cost areas simply due to transmission constraints. Similarly, if one of the state's IOUs substantially over-complies with their RPS, RECs allow that IOU to dispense of its excess compliance to other, non-compliant utilities or ESPs.

Facilitation of ESP Participation in the RPS

Under SB 1078, ESPs are required to comply with the RPS over time. Some ESPs will have RPS requirements that begin in 2002. Many ESPs, however, will be hard pressed to meaningfully participate in the RPS requirement. As with PG&E and SCE, who are not yet credit-worthy, many ESPs lack the credit that would be necessary to support the financing of new renewable generation. Moreover, with uncertain and small customer loads, many ESPs will also be hard pressed to match intermittent or variable sources of renewable electricity generation with their customer loads. Thus, many ESPs will be unable to offer attractive long-term electricity contracts to renewable generators. With a REC system, however, a renewable generator may be able to find a willing buyer for the electricity from a larger, credit-worthy counter party, with RECs then sold to the ESP. Such transactions will often be preferable to both the generator and the ESP.

Lower Transaction Costs for Market Participants

REC systems may also impose a lower transactional burden on market participants: renewable energy generators, IOUs, and ESPs. Rather than tracking individual contracts and using attestations and costly third-party audits to verify the purchase or sale of renewable generation, electronic systems simplify the renewable energy contracting and verification process. Related, RECs provide the most flexible compliance mechanism for the RPS because, if allowed by regulation, RECs can be banked, borrowed, or traded quite easily.

Due to these numerous advantages certificate-based systems have emerged as the most common method for accounting for renewable generation and for preventing double-counting of renewable generation. New England, having attempted and failed to design an effective contract-path system, recently switched to a certificates system. Nevada, a state with an RPS that borders California, has also recently endorsed the use of a REC compliance system for their RPS.

Adaptability of RECs to Other Compliance and Accounting Requirements

SB 1078 requires that the Energy Commission's accounting system not only serve RPS compliance purposes, but also be used for "verifying retail product claims in this state or any other state." The Energy Commission takes this language to mean that, at a minimum, the accounting system is to also be used to verify compliance with the State's power source disclosure requirements (SB 1305) and to monitor the possible future disbursement of funds from the Energy Commission's Customer Credit Account.

As the wholesale renewable electricity market, and thus the RECs market has evolved, market participants and regulators have acknowledged the need for reconciliation of claims and RECs transactions across borders. The Energy Commission is currently working with a group organized by the Western Governor's Association to investigate the potential of a WECC-wide RECs tracking system. In addition, there is an effort to form a national RECs tracking network with a central American Association of Issuing Bodies that would link states and regions that have certificate based systems. All of these efforts would support California's use of the RECs approach.

As the uses of the Energy Commission's accounting system increase, so to does the need for simplified verification and assurance of no double counting. As already clearly indicated, because certificate-based systems are highly automated, they have great flexibility and expandability: a REC system is likely best able to serve the multiple needs contemplated by SB 1078.

The creation of a certificate-based accounting system may also have ancillary market benefits that are consistent with the CPUC and Energy Commission's goal of increasing renewable generation in the State. These benefits may come from the facilitation of (1) retail REC-only products, and (2) the use of RECs in pollution credit markets:

Retail REC-only Product

RECs are being sold separately from electricity in California and across the country as a stand-alone product to end-use customers. There are currently about a dozen companies that are featuring RECs as a stand-alone "green power" product. These types of products are frequently marketed to consumers on the internet by independent companies not serving electricity load. In addition, programs in Oregon and New York now allow RECs from competitive suppliers to be sold through utility programs.[22] The creation of a REC establishes property rights and creates a currency that can be bought or sold individually from electricity by end-use customers. By developing a certificate-based accounting system for RPS compliance, California will therefore also create a system that may facilitate and expand customer-driven demand for renewable energy in, and potentially outside, the state.

Pollution Offset or Environmental Compliance

RECs may in the future be used in pollution credit markets. To do so, RECs must be converted from an energy tool measured in MWh to a pollution tool, denominated in units of pollution. Depending upon the pollution offset credit being calculated, there may be the need for information on the date and time of generation, geographic location of the generator, as well as the location to which the energy was sold. Although there are few examples in the U.S. where a REC has been converted into a pollution offset or pollution credit for environmental compliance purposes, RECs are regularly used by large companies and others that want to voluntarily reduce their emissions profile, or boast of a climate neutral footprint. In addition, EPA's Green Power Partnership program promotes the purchase of RECs by businesses and has lead discussions about how RECs may be used in the future in state or federal emissions trading programs.[23]

Appendix A. Renewable Energy Certificate Systems

The Texas RPS and REC Tracking System

Texas has rapidly emerged as one of the leading wind power markets in the United States. This development can be largely traced to a well-designed and carefully implemented renewables portfolio standard (RPS). To meet the state's RPS requirement, Texas was the first U.S. state to develop a fully functional system for tradable renewable energy credits (RECs). Here we briefly discuss the design of the Texas RPS and provide a more detailed account of the RECs system that was created to account for and verify compliance with the RPS.

Texas RPS Summary[24]

In May 1999, the Texas government established an RPS within the restructuring of the state's electricity market.[25] Detailed RPS regulations were subsequently established by the Texas Public Utilities Commission.[26] The regulatory process to design the rules of the Texas RPS began in June 1999 and proceeded rapidly, with final rules completed in December 1999. The Texas ISO, ERCOT, was appointed to be the program administrator of the RECs program in May 2000. Texas' RECs system began operations 18 months after rules were set, in July 2001, with the first RPS obligations applied in 2002.

The Texas RPS requires the installation of 2000 MW of new renewable capacity by the year 2009, in addition to preserving the 880 MW of renewable energy already on line. This translates to about 3% of present electricity consumption.[27] This goal is modest relative to the enormous potential for renewable energy development in Texas, but it represents a marked increase in renewable energy capacity in the state.

Intermediate new renewable capacity goals in Texas are 400 MW by 2003, 850 MW by 2005, 1400 MW by 2007 and finally 2000 MW by 2009. These capacity goals are translated into megawatt-hour based energy requirements by using an average capacity factor of all eligible renewable plants; its value is initially set at 35% and will be adjusted over time based on actual plant performance.

Electricity retailers that serve markets open to competition are obliged to fulfill their portion (based on yearly retail electricity sales) of the renewable energy requirement by presenting RECs to the regulating authority on an annual basis. The obligation begins in 2002 and ends in 2019.

A tradable REC is issued for each MWh of eligible renewable generation located within or delivered to the Texas grid, meaning the entire Texas grid, including areas outside of ERCOT. With the exception of renewable power plants with a capacity smaller than 2 MW, which are eligible irrespective of their vintage, the REC trading program is restricted to facilities erected after September 1, 1999. A wide variety of renewable technologies are eligible. Table 1 summarizes the design features of the policy.

Table 1: The Texas RPS: Design Details

Design Element	Design Details
Renewable energy purchase obligations of eligible new renewable generation	Capacity targets: 2003 - 400 MW 2005 - 850 MW 2007 - 1400 MW 2009 - 2000 MW (through 2019) Annual energy-based purchase obligations: begin in 2002 and end in 2019 derived based on capacity targets and average capacity factor of renewable generation (initially set at 35%)
Obliged parties	Who: All electricity retailers in competitive markets (80% of total Texas load.) Publicly-owned utilities must only meet the RPS if they opt-in to competition. Metric: obligation based on their proportionate yearly electricity sales;
Eligible renewable energy sources	Vintage and Size: new renewable power plants commissioned after September 1, 1999 and all renewable plants less than 2 MW capacity, regardless of date of installation RECs Offset Vintage: purchases of renewable energy from plants larger than 2 MW and built before September 1999 may count towards a supplier's REC obligation, but are not tradable Resources: solar, wind, geothermal, hydro, wave, tidal, biomass, biomass-based waste products, and landfill gas Location: facility must be located within or delivered to the Texas grid DG and DR: renewable energy sources that offset (but do not produce) electricity (e.g., solar hot water, geothermal heat pumps), and off-grid and customer sited-projects (e.g., solar) are also eligible
Tracking and accounting method	Method: tradable renewable energy certificates Compliance Period: calendar year Grace Period: 3 month grace period allowed for fulfillment after compliance period ends Operations: web-based certificates registry, tracking and retirement
Certificates	Creation: issued on production, 1 REC/MWh Banking: 2 years of banking allowed after year of issuance, borrowing of up to 5% of the obligation in first 2 compliance periods allowed
Regulatory bodies	Regulator: Texas Public Utilities Commission establishes RPS rules and enforces compliance Administrator: ERCOT Independent System Operator
Enforcement	Penalty: the lesser of 5(U.S.)¢/kWh or 200% of mean REC trade value in compliance period for each missing kWh

Texas's RECs Policy Background

Texas developed the first comprehensive RECs system in the U.S., a web-based platform that provides for the issuance, registration, trade, and retirement of RECs. The platform facilitates the tracking of RPS compliance, but does not provide the "market making" function of a certificate exchange, as this function is to be the left to the private marketplace, as will REC brokering and financial markets.

Texas' RPS was contained within the state's electricity restructuring legislation, and that legislation also specified that RECs were to be used to meet the policy's goals. Texas' RPS rules, completed in December 1999, laid out the broad design of the Texas RECs program. In May 2000, the Public Utility Commission of Texas (PUCT) assigned the REC program design and administration responsibilities to the Electric Reliability Council of Texas (ERCOT). ERCOT subsequently developed detailed operating rules for the RECs program (with the help of a consultant, and with detailed public workshops and comments from stakeholders), which were completed in late 2000, and issued an RFP to identify a contractor to build the system's software. The Automated Power Exchange (APX) was tapped to build the software in late December 2000, and the system was completed and delivered to ERCOT in April 2001 (approximately 4 months after APX was selected to build the software). The REC Program, which only tracks renewable energy certificates, started operating in July 2001and has been in operation for a year and a half.

There are two categories of certificates in the Texas REC Program: Renewable Energy Credits (RECs) and REC Offsets. A REC is from a new renewable facility; a REC Offset is from an existing renewable facility. Pursuant to Texas law, only RECs may be traded.

Texas's RECs Operational History

Though designed principally to meet RPS compliance needs, Texas' RECs system has also found other uses. In particular, it is used by green power marketers to procure renewable energy in Texas. Texas RECs have also been purchased by out-of-state entities for the purposes of green power marketing and green claims.

Currently there are about 950 MWs of new renewable generation capacity in Texas, which will result in approximately 2.5 million RECs created during 2002. ERCOT, as the Program Administrator, is currently managing over 150 market participant accounts (some market participants have multiple accounts), 54 of which are competitive retailers in the new Texas restructured electric market (the remainder include 23 REC generators, 19 brokers, 28 traders, 11 exchanges, 10 aggregators, and 10 other). REC account holders include participants from several states outside Texas and at least two countries other than the U.S.

Most of the new renewable projects in Texas have sold their electricity and RECs in a bundled fashion to large retail electricity providers under long-term (10-20 year) contract. With 950 MW of new renewable generation on-line, and just a 400 MW RPS requirement in 2002, these larger electricity providers have subsequently sold some of their RECs to other parties in and outside of the state. RECs were traded during early 2002 at $4/MWh. Since then, due to transmission constraints and other factors (including the possibility of some market power), REC prices have risen. REC prices reportedly reached a high of $17-18/MWh over the summer, and by the end of 2002 receded to approximately 12/MWh. Prices have been generally lower for future RECs delivery, at $6-9/MWh for RECs generated in 2005.

Texas RECs Participation

Participation in the REC program is mandatory only for retail electricity providers (described more generally here as load serving entities, or LSEs) participating in the competitive retail market in Texas, who must therefore meet RPS obligations. Renewable generators and REC aggregators (who are aggregating RECs from small-scale renewable generation units) also participate in the program because it is the only way to sell RECs for purposes of RPS compliance, though they do so voluntarily. Other parties may also participate in the REC Program, for example, a third party broker that facilitates transactions.

Texas's RECs and REC Offsets Creation

A Texas REC represents all of the renewable attributes associated with one MWh of production from a certified renewable generator. RECs are allocated to certified REC generators on a quarterly basis by ERCOT based on metered production that is electronically transferred to the database.

Each REC issued contains the following information. This information is coded to form a unique serial number for every REC produced.

- Date generated (quarter/year)
- Type of renewable resource
- Facility ID number (assigned by ERCOT; fixed for life of facility, regardless of changes in ownership)
- REC number (numbered 1 through the total number of MWh generated by the facility in a quarter)

REC Offsets are awarded to an existing renewable generation facility based on its 10-year historical average of energy output. Offsets may be used in place of a REC to meet a renewable energy requirement only by that entity assigned the offsets and only when they opt to participate in the newly restructured retail market in Texas. REC Offsets cannot be bought, traded, sold, or retired. The PUCT issues REC Offsets once and the Offsets are good until the PUCT revokes them or until the generating plant is no longer generating electricity. The REC Offsets are held in the Offset generator's account until it assigns those Offsets to the buyers of electricity for their use when they opt into retail competition in Texas.

Texas's RECs Data Source

ERCOT receives metered generation data electronically directly from the generators based on actual measured production on a daily 15-minute basis. This information is downloaded into the REC software on a monthly basis. Data used for calculations is settlement quality data. If the REC generator or REC Offset generator does not have interval metering, the PUCT is obligated to define a methodology for determining the amount of REC generation or REC Offset generation that has occurred.

To calculate the REC requirement for RPS compliance of each LSE, ERCOT requires each LSE to provide monthly load information such that ERCOT can calculate the MWh consumed by Texas customers served by the competitive retailer.

Texas's RECs Generator Registration

REC generators or aggregators must apply to the PUCT for certification to produce or aggregate RECs. Once registered, the PUCT notifies ERCOT of the certification and the REC Generator will log on to the www.texasrenewables.com web site and establish their trading account.

REC Offset generators must have applied to the PUCT for certification by July 31, 2001. After a REC Offset generator is certified, a REC Offset recipient can be identified and certified. The REC Offset generator will deposit the REC Offsets into the recipient's account as described above.

Both REC generators and REC Offset generators can be decertified. ERCOT verifies that generation is occurring when metering is available to do so. If metering is not available, it is the obligation of the PUCT to verify production and assess whether the PUCT's RPS rule is being met.

RECs may also be produced by generators that are not located in Texas if (1) the first metering point for such generation is in Texas and is for Texas use, and (2) all generation metered at the location of injection into the Texas grid comes from that facility. Such generators must also be certified by the PUCT. These rules effectively limit the program to in-state generators.

Texas's RECs Transfer

RECs are easily transferred between account holders through a web-based platform. The act of negotiating the price and other details of the sale or purchase of renewable electricity or RECs alone is negotiated privately through traditional methods. However, the REC transfer does not occur until the initiator or seller requests a transfer on the ERCOT site and it is confirmed by the receiving party. After this occurs, the REC Program will transfer RECs between accounts. REC Offsets may not be transferred to another account holder.

Texas RECs and REC Offsets Retirement

RECs are retired from the system under three circumstances: mandatory compliance (e.g. RPS), voluntary retirement (e.g. green power sale), or expiration. The account holder must designate to ERCOT which RECs it wants to retire for the mandatory or voluntary retirement. ERCOT will automatically retire RECs each year that have expired. REC Offsets are not retired.

Texas RECs and REC Offsets Lifetime

RECs have a useful life for RPS compliance purposes of three "compliance periods," or stated differently, the calendar year in which the REC was generated plus two more full years. If a REC is not used to meet a compliance purpose, it will be retired at the end of the first quarter of the fourth year. For example, a REC generated in 2004 can only be used to meet Texas RPS compliance in the years 2004, 2005, and 2006, but it can still be used for all other purposes, such as private REC sales, until March 31, 2007 when all remaining RECs from 2004 are retired. REC Offsets are considered valid until the PUCT notifies ERCOT that they are no longer valid.

Texas's RECs Information Verification

ERCOT and the PUCT reserve the right to request supporting documentation to allow verification of generation quantities as needed. Non-metered monthly load and generation data are submitted to ERCOT and that information is stored for historical and verification purposes.

Texas RECs Reporting and Public Access to Information

ERCOT is responsible for generating regular reports summarizing the transactions of the REC program. ERCOT publishes a list of REC account holders with contact information to facilitate REC trading, and provides non-competitive information on REC generators, such as facility name, REC ID numbers, resource type, location, etc. ERCOT also posts each month the total aggregate energy sales in MWh of competitive retailers in Texas for the previous month and year to date. Finally, for broader use, ERCOT posts a table that contains the CO_2, SO_2, NO_x and particulate matter emissions data supplied by the PUCT and based on the Texas Natural Resources Commission (TNRC) standards on an emissions per MWh or tons of fuel used basis for each energy type.

The New England Generation Information System

Beyond Texas, the only other fully functional and operational system for tradable certificates in the United States is in New England, where the NEPOOL Generation Information System (NE GIS) tracks all electricity generation via a certificate system in the six New England states (Maine, New Hampshire, Vermont, Massachusetts, Rhode Island and Connecticut.)

GIS Policy Background

The NE GIS and was established to account for various attributes of energy transactions in the NEPOOL transmission region for the purposes of verifying compliance with individual state RPS mandates, emission and power content disclosure statements, and to establish a trading platform to facilitate compliance with these mandates. No financial information is recorded in the GIS database. The system was built by the APX, who is also serving as the Program Administrator for the first five years (unlike in Texas, where APX merely designed the software).

A NEPOOL working group consisting of market participants (generators, marketers, etc.), regulators, and other interested parties developed the design of the NE GIS. The Working Group was formed in 2000, in part as a result of the failure of previous "contract-path" tracking systems to create a seamless regional tracking system. An RFP for the design and administration of the system was distributed in 2001, after which APX was selected. It took the APX approximately 6 months to design the system. Final NEPOOL approval of the operating rules was provided in January 2002, and the system became operational in July 2002.

The cost of developing the NE GIS was $2 million; $500,000 was paid up front during the software development period and the remaining cost is being amortized over the first five years of operation, while APX is serving as the Program Administrator.

GIS Operational History

The NE GIS, which is administered by the Automated Power Exchange, is issuing and tracking about 30 million electricity certificates per quarter over the first six months of its operation. Approximately 6 million certificates were traded during the first quarter of trading. Much of the current trading of certificates is for state RPS compliance purposes. Current prices for GIS certificates eligible for the Massachusetts RPS are $20-25/MWh.

GIS Operational Design

The design of the NE GIS is detailed below. Key features that differentiate this system from the RECs system in Texas are as follows:

More Comprehensive System

The New England system tracks generation not only for RPS compliance, but also for disclosure and emissions regulations. Accordingly, the system generates certificates for all sources of generation in New England, and tracks a greater number of generation "attributes", including emissions characteristics. The New England system is therefore a good model of a system that serves multiple purposes, while Texas offers a simpler solution for just RPS compliance.

Multi-State and Treatment of Electricity Imports

The New England system must account for generation located within the entire multi-state region, and must also account for electricity generation in surrounding regions that is imported into the state. Texas' system need not account for multiple states.

More Rigid Flexibility Rules

The Texas RECs system allows for three years of credit banking and has a calendar year settlement period. The New England GIS system, on the other hand, has a quarterly settlement and trading system for certificates, with no banking. Some market participants have claimed that the limited flexibility in New England is reducing the value of the system for RPS purposes, though the vintage limitations were specifically established so that the system could easily accommodate disclosure and emissions requirements, in addition to state RPS mandates.

GIS Participation

The NE GIS accounts for all generation in NEPOOL central dispatch, both renewable and non-renewable generation. In addition, all LSEs in New England are required to have accounts in the GIS system, with the exception of any LSEs that are not required to meet state mandates, for example some electricity co-operatives or municipal providers. This type of power provider as well as market participants located outside of the NEPOOL central dispatch control area may voluntarily participate in the NE GIS.

GIS Certificate Creation

The GIS administrator issues a GIS certificate for every MWh of generation in the NEPOOL control area or imported into the NEPOOL control area, based on the wholesale energy market settlement data received from the independent system operator. GIS certificates are created on the 15th day of the quarter two calendar quarters after generation has occurred. So, for example, all generation occurring in the first quarter of the year are issued certificates on July 15th. The certificates are numbered; the minimum denomination is one MWh. Once the GIS certificates are created, they are deposited into the generators account, establishing the generator as the original owner of the certificate until it is transferred.

The following information is carried on each certificate:

- Certificate serial number
- Facility name and location
- Fuel type
- Eligibility for regulatory programs in each New England state
- Emissions characteristics for CO, CO2, Hg, NOx, PM, PM10, Sox, VOCs
- Vintage of the generating facility
- Generator installed capacity
- Certificate born on date (mm/yy)

- Control area (interconnect)
- Labor characteristics
- Green-e registration number

GIS Source of Data

The GIS database uses monthly financial settlement data from the New England Independent System Operator for generation within New England, and for imports and exports to and from the system (smaller generators that the ISO does not "see" will be accommodated in other ways). Transfers and other wholesale transactions are recorded in the database by the parties involved as they occur. Retail load obligations are ascertained by the GIS Administrator based on a combination of information from the system operator and information provided by the load serving entities. Other information about the generating units not accounted for by the system operator, such as labor characteristics or generation information from non-NEPOOL generators, can be provided to the GIS administrator directly.

GIS Generator Registration

GIS generators and account holders owning generation outside of the NEPOOL control area must register the disclosure attributes of each of their generating units with the GIS Administrator. This information is included on the certificate when issued. This generator information is verified by state regulatory authorities.

Retail Electric Sales Verification

Retail sales of electricity are recorded in each LSE's account through a mechanism known as a "certificate obligation." One certificate obligation is assigned for every MWh consumed. The certificate obligation can be satisfied by either the direct purchase of specific certificates (for example, renewable certificates purchased from a qualified generator) or can be satisfied with "residual mix" certificates that represent the attributes of the entire system, minus any specific purchases. Direct purchases of certificates are recorded in the GIS database through a transfer of certificates from one account holder to another.

GIS Certificates Transfer

GIS certificates may be transferred through a variety of mechanisms. The NE GIS contains a bulletin board function to allow suppliers to show their GIS certificates available to interested buyers. Buyers and sellers can also arrange transfers of GIS certificates through bilateral contracts or private arrangements. However, the purchase of energy out of the system does not include GIS certificates unless they are specifically transferred. Regardless of the exchange process used, all transfers of GIS certificates between accounts is noted in the GIS database and confirmed by the both parties. GIS certificates are eligible for transfer for roughly 60 days, from the day they are created (15th day of the quarter) until 15 days before the end of the quarter.

GIS Reserve Certificates

Any NE GIS participant that sells renewable certificates directly to an end use customer, separate from electricity, may do so by setting the status of such certificates to a reserved state. Renewable certificates that are set-aside in reserve must be transferred to a bona fide third party before the end of the trading quarter. At the end of the trading quarter, all reserve certificates will be retired.

GIS Imports Accounting

All energy imported into the control area will be accounted for through the creation of GIS certificates for the amount of energy imported. The imported energy will reflect the generating attributes of the specific generation unit if the generator of the imported energy meets all of the following criteria:

- The imported generation is eligible for one of the New England states' RPS;
- The imported generation is settled in the monthly settlements of the New England System operator;
- The generating unit is registered with the NE GIS Administrator and has provided all relevant data needed for the NE GIS Administrator to verify the attributes of such imported energy;
- The energy is imported from a generating unit in an adjacent control area with transmission rights over the ties to the New England Control Area;
- The generator can verify for the GIS Administrator that such energy generation occurred;
- The generator has certified that the attributes have not been sold, retired or otherwise claimed by another party in another jurisdiction; and
- A NERC tag has been issued.

If the imported energy does not meet these criteria, GIS certificates for imported energy will be given the attributes of the most recently available overall mix of fuel sources and emissions of the source control area.

The GIS Administrator will notify the adjacent regulatory agencies on a quarterly basis about the creation and retirement of NE GIS certificates from imported energy.

GIS Exports Accounting

Energy exported from the New England control area will be recorded through a parallel movement of GIS certificates from the GIS account holder's account to the transferee's account. The GIS certificates associated with the exported energy will contain the attributes of the generating facility if essentially the same criteria as imports are met. Otherwise, the exported energy will have the attributes of the residual mix.

GIS Certificates Retirement

The NE GIS is organized in quarterly trading periods. At the end of each trading period, all trading is stopped and all GIS certificates generated during that quarter are accounted for and retired. Any GIS certificates that are not held in an LSE's account are used to calculate the residual mix. The residual mix is simply the weighted average mix of all unaccounted for GIS certificates (equivalent to the generation occurring in the trading period, minus any generation that has been removed through the direct purchase of certificates). Any LSE that has a certificate obligation that has not already satisfied it with purchased certificates is assigned residual mix certificates. After this time, all accounts are closed, reports are available, and a new trading period begins.

GIS Reporting and Public Access to Information

The GIS administrator provides account holders and New England regulatory agencies with quarterly and annual reports, respectively. In addition, there is a publicly accessible portion of the GIS website, www.nepoolgis.com, that will contain a directory of all account holders for the reporting period and, for each account holder, the following information:

- Name, address, phone, fax, website and email,
- Total exports in MWh for the four most recent quarterly trading periods,
- Total number of reserve certificate transactions for the four most recent quarterly trading periods,
- An aggregation and/or average of the certificate fields for all certificates created during the reporting period,
- And for GIS generators,
- Facility ID number,
- Fuel source(s),
- Eligibility under state RPSs,
- Total generation in MWh for the four most recent quarterly trading periods,

And for retail load serving entities,

- Total certificates obligations (retail sales) for the four most recent quarterly trading periods,
- Total imports in MWh for the four most recent quarterly trading periods.[28]

Renewable Energy Credits: Developments in Other States

There are several other efforts underway to develop certificate tracking systems in the U.S. that deserve note.

Wisconsin

Wisconsin is developing a system to track renewables purchased by the local utilities in excess of their renewables portfolio standard mandates. The certificates issued are referred to as Renewable Resource Credits (RRC). RRCs are issued to the utilities for any renewable generation that was purchased in excess of the state's renewables mandate in a given year, and was served to utility customers. The RRCs can then be traded between the utilities or held for future compliance. An unlimited banking period for RRCs currently exists in Wisconsin for RPS purposes. The tracking system is expected to be launched in February. The system is being built by Clean Power Markets and Zyquest. The cost of construction is $50,000 and the annual administration and operations are estimated to be $65,000. There was a public input process, including a list-serve for comments and several meetings over the course of about one year. It will take approximately 5 months to construct the system.

Mid Atlantic

In the Mid-Atlantic, an ad hoc committee of interested stakeholders has been meeting to discuss the formation of a generation attribute tracking system for the PJM interconnection electricity region. This ad hoc group has recently been officially recognized as a "Working Group" under PJM, which gives it the ability to make recommendations to the PJM System Operator for operational changes. This group is discussing and defining the design features of the certificates tracking system for PJM, which is being expanded to include significant portions of the Midwest and Southeast. The system as currently envisioned by some parties would create certificates for all energy attributes, though great debate exists on the specific design and functionality of the system. There is no calendar for when the system will be built, and there is also not a clear funding mechanism for creating the software.

New York

In New York, NYSERDA has funded two groups to develop business plans around the potential creation and design of a certificate tracking system to replace the state's current hybrid tracking approach. While it is not clear that the state will move quickly in this direction, the recent announcement of a state RPS may hasten the development of such a certificates system.

Western Governors Association

The Western Governors Association has also formed a steering committee to explore the design and development of a tracking system for 11 states in the Western U.S. This group has held one meeting where a decision was made to move forward with a stakeholder process to begin discussions on functional and design features of the system, costs, and contributions. This stakeholder effort has been stalled due to a lack of funds, but is expected to start up again in the Spring 2003.

Other States

In addition to California, there are three other Western states that have recently passed rules that are expected to lead to the development of either a western states certificate tracking system or a loose network of state certificate tracking systems in the west. The **Nevada** Public Utility Commission recently passed a rule to establish a certificate based tracking system to verify compliance with the state's renewables portfolio standard. This rules specifies the development of a renewable certificate tracking system. **New Mexico** also passed a renewables portfolio standard that specifies renewable certificates as the method for accounting and compliance verification. **Arizona's** small, solar-focused RPS also allows for certificate trading. Finally, both **Oregon** and **Washington** have environmental disclosure labels that require some method of accounting for imports and exports into their states and have active REC trading markets. These two states have indicated a strong interest in a western certificate tracking network.

If these diverse efforts move forward, a good fraction of the country will be covered by a state or ISO operated/sanctioned certificate tracking system. In addition, interest is growing to designate a potential default certificate "Issuing Body" for generators located in states where there is no government sanctioned certificate system. While the outcome of these discussions is not yet clear, a default Issuing Body will effectively allow all renewable generators to voluntarily participate in a national REC tracking network.

Appendix B. American Association of Issuing Bodies

Introduction and Background

The U.S.EPA is funding work to formally establish a North American Association of Issuing Bodies (AAIB). The AAIB will facilitate communication among Issuing Bodies and renewable energy programs within the U.S., Canada and Mexico. In addition, the AAIB is intended to develop an framework for addressing immediate U.S. market issues relating to issuing, registering and tracking RECs transactions as well as establish property rights for RECs owners.

The AAIB development effort includes establishing a governance structure, development and negotiation of the agreements governing the interaction of the Issuing Bodies with AAIB, and with each other, to ensure compatibility of information transfer between Issuing Bodies.

Today the U.S.EPA buys RECs for its own facilities' green power commitments and uses RECs as a compliance method for participation in their Green Power Partnership Program. In addition, the U.S.EPA is interested in allowing for the potential exchange of RECs for emissions credits. As with emission credits, national coordination of RECs is required to confirm that RECs retired in one system are not also being retired in another system, a situation known also as "double-counting."

The AAIB protocols are envisioned to have sufficient flexibility to allow for individual regional and national differences while not compromising the integrity of individual programs. Two regulated RECs Issuing Bodies now exist, in Texas and New England. RECs are extensively traded in other regions of the country outside of a state or regionally supported structure. Several states are in the process of developing protocols for using RECs to satisfy renewable purchase mandates.

Establishing an AAIB will allow additional Issuing Bodies to develop accounting systems to be compatible with and serve a national RECs network and the rapidly growing RECs market. Single state or single region tracking systems are not able to definitely protect consumers from double-counting of RECs moving between states or regions without the cooperation of neighboring systems. Likewise, if RECs accounting systems are established in some areas with limited capability and are incompatible with regional RECs trading outside of regulatory mandates, the U.S. will quickly become balkanized and consumer protection will not be assured.

Importantly, the incremental cost of designing a system that will accommodate certificate markets as well as regulatory programs is negligible while the cost of trying to change a system later is significant.   The AAIB provides the forum for common standards and protocols to be developed and for cooperative agreements to be formed. The AAIB is based on a model developed in Europe for linking together the RECs tracking systems of individual countries into a EU-wide tracking and trading RECs platform.

Organizational Structure

The structure recommended for the formation of an integrated network consists of three key elements:

American Association of Issuing Bodies (AAIB)

The intent of the AAIB is to establish a policy-neutral North American accounting system to register and track RECs ownership and retirement in wholesale markets.[29] The AAIB will lead the effort to develop some basic trade rules and minimum protocols for North America, called the 'Basic Commitment.' The Basic Commitment contains general principles that preserve transferability and accuracy of information but it does not govern how a specific Issuing Body operates. The draft Basic Commitment will be discussed and modified through a stakeholder process[30] directed by the AAIB. Ideally, each Issuing Body will incorporate these guidelines and minimum operating procedures into their own operating rules. The rules governing AAIB processes (Rules of Association) and activities will be developed and approved by the AAIB member participants.

Issuing Bodies

Issuing Bodies will be established for different regional domains in North America. A domain will be defined by geographical boundaries (e.g. state, power pool, country, or region) such that a renewable generating facility is assigned to one and only one domain. Each Issuing Body will develop its own operating rules consistent with the laws and renewable energy programs in its geographic domain and will agree to abide by the procedures established for cooperation with other Issuing Bodies outlined in the AAIB Basic Commitment.

The conceptual model for the AAIB contemplates two general types of Issuing Bodies: Issuing Bodies for mandatory programs and Issuing Bodies for voluntary purposes. A single Issuing Body could fill both of these roles. The Issuing Bodies for mandatory programs will most likely have some regulatory designation from the state or region where it is operating. An Issuing Body established for voluntary registration of RECs would also have to follow the guidelines of the Basic Commitment, but would not necessarily be operated by any regulatory authority. For example, a voluntary Issuing Body could be run by a private business, a non-profit, or a transmission system operator.

The chief responsibility of an Issuing Body is to ensure the accurate issuing, tracking, and retiring of RECs for any given generator and to verify the information supplied by generators. The mechanism for issuing, tracking and retiring RECs will be developed by each Issuing Body, however, they will need to meet the minimum standards in the Basic Commitment to ensure compatibility with the larger network.[31]

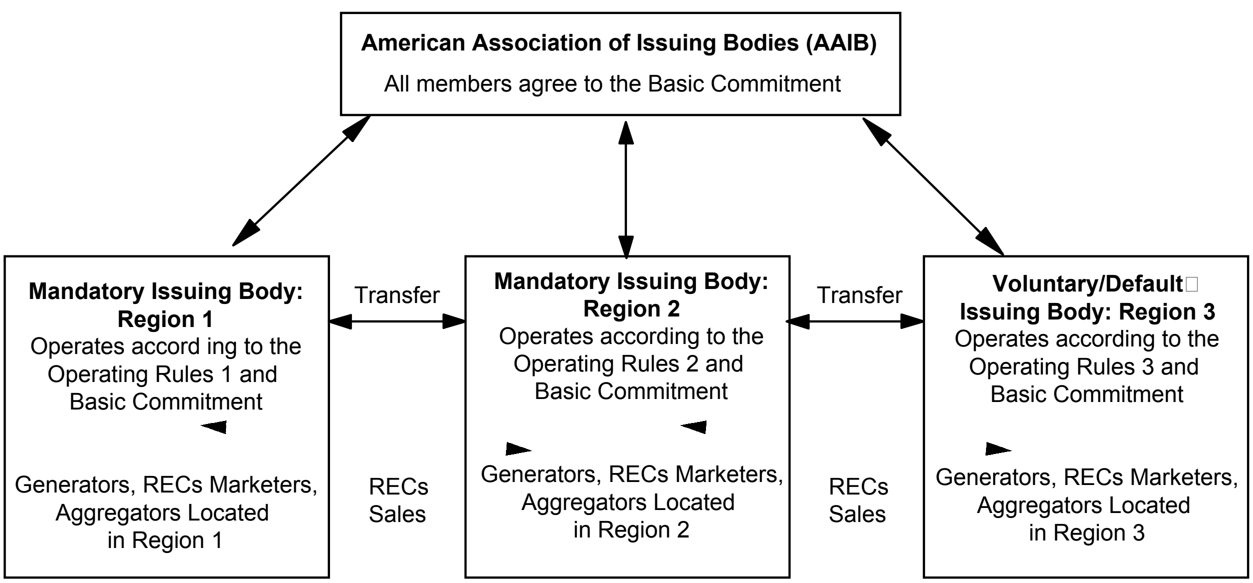
A second responsibility of the Issuing Body is to ensure that information is transferred and shared between Issuing Bodies when necessary and appropriate, e.g., when RECs are sold into a neighboring region with a different Issuing Body. This integrated accounting approach minimizes the opportunity for double counting RECs that are bought or sold in other regions. The AAIB will work through these coordination issues with stakeholders in advance of system specification finalization and investment. The goal is to make sure there is seamless coordination between Issuing Bodies so that a national network of Issuing Bodies is operational.

A third responsibility of the Issuing Bodies is to register generators and periodically verify the information provided by generators such as type of technology/fuel and operational status.

Market Participants

The third component of a North American RECs tracking network is market participants, including renewable energy generators, marketers, wholesale purchasers, aggregators, large end-use customers, product certifiers, and traders. These market participants must voluntarily agree to participate in such a system, unless they are located in a region where participation is mandatory, such as New England. Market participants will be involved in the development of the Basic Commitment and the relevant operating rules because of their valuable perspective on the functional requirements of a robust market.

Diagram 1: Organization Structure of a North American RECs Tracking and Verification Network



Plan and Schedule for AAIB Formation

The following outline lays out the plan and schedule for AAIB development.

Phase I: Nov 2002 – March 2003
Initial meetings with potential and emerging Issuing Bodies
Release *Basic Commitment* Draft to potential and emerging Issuing Bodies
Develop preliminary '*Rules of Association*' for AAIB
Investigate idea of generator registry
Determine candidate stakeholders, form three primary stakeholder groups
Potential Issuing Bodies, regulators
Market participants, RECs marketers
Interested stakeholders that don't fall in above two categories

Phase II: March 2003 – September 2003
Establish Steering Committee to flesh out details of *Rules of Association*
Host stakeholder meeting to review *Basic Commitment*
Revise *Basic Commitment* – send out to individual Issuing Bodies for approval

Phase III: September 2003 – December 2003
Host stakeholder meeting to introduce *Rules of Association* for AAIB members
Revise *Rules of Association* – send out for approval by potential Issuing Bodies
Develop Security/Data Integrity requirements document
Go through legal/admin work to establish AAIB as separate non-profit

Phase IV: January 2004 -
Finalize/ get approval (by Issuing Bodies) of *Basic Commitment*
Finalize/ get approval of *Rules of Engagement*
Finalize/get approval of Security/Data Integrity document
Incorporate AAIB

Appendix C. Oregon and New York REC-Based Utility Buy-Through Programs

Introduction and Background

With the CPUC's suspension of customers' right to choose direct access as of September 20, 2001, no incremental customers may select green power offerings. As described in Section 1 of this report, without changes to the legislative and regulatory rules related to the Customer Credit Account, demand for account funds is likely to remain stable or decline over time. The main report discusses the options for expanding demand and impact of the Customer Credit Account, while this appendix details an alternative competitive green pricing program option in use in Oregon and New York.

In the two programs described in this appendix, competitive green power offerings are made available by and through the utility, and are invoiced through the utility bill. In Oregon, the two investor-owned utilities (IOUs) bid out for a single supplier to provide renewable energy credits (RECs) and support joint and solo program and product marketing. In this case, the RECs are rebundled with IOU provided energy and sold as "green power." In the Niagara Mohawk (NiMo) example, the utility provides access to the customers by a slate of approved RECs retailers who are selling only the renewable RECs and who market largely independently of the utility.

The context for the two programs differs considerably. In Oregon, small customers are only provided choice through their utility, whereas in New York, choice has been available by years. However, in New York, residential switching rates have varied substantially by utility service territory and in Niagara Mohawk's territory, market dynamics have not been favorable to entice competition for smaller customers. Both programs are implemented via RECs transactions, although in New York RECs are described as "conversion transactions" authorized under the state's Environmental Disclosure regulations and accounted for by the Public Service Department's Environmental Disclosure Administrator.

Summary of Findings

If considering support of mass market RECs products, it makes sense to consider a hybrid RECs/utility-sponsored green pricing option, for the following reasons:

1. The benefits of competition can be captured in the absence of retail electricity competition, including:
   - Differentiation from standard utility supply is more likely in a competitive environment than under a single green pricing choice offered only by the distribution utility;
   - Competitive pressure tends to improve the value for a given price;
   - Competitive positioning increases customer awareness and increases credibility of a new product offering;

- Product differentiation will offer a portfolio of products appealing to a wider array of customers than a single offering;

2. The administrative ease of RECs is meshed with the credibility of a utility green pricing program with the potential for vastly superior market penetration (and lower customer acquisition and retention costs) compared to traditional RECs products sold independently of the distribution utility; and
3. Such and option can serve as either a smooth transition to the possible future reopening of direct access, or as a substitute means for effectively developing a green power market in the absence of direct access.
4. This option does not require switching electric suppliers, eliminating the burden of educating customers that their reliability will not be compromised if they switch suppliers.

RECs purchases can have an equivalent environmental and electric system impact to a direct access green power offering[32], but in the mass market, suffers from the disconnect with electric service. Smaller customers perceive a RECs purchase akin to a charitable contribution rather than a product or service. As a result, there is a greater educational burden on marketers so most observers expect mass marketed RECs products to have a lower market penetration than a product offered in association with the purchase of electricity and invoiced through the electric bill. Thus, while such a program can be offered to both large and small customers, its advantages relative to the RECs market are greater for smaller customers, for whom one-on-one marketing is not used, the effort to explain tags products is not cost-effective, and the sophistication to understand tags products is less prevalent. On the other hand, a RECs product rebundled with utility electricity to form a green power product has the ease of the RECs procurement with none of the hassles of RECs mass marketing.

The Oregon Program

In July 1999 Oregon Senate Bill 1149 restructured the state's investor owned utility (IOU) electricity market. SB1149 required the state's IOUs – Portland General Electric (PGE) and PacifiCorp's Pacific Power - to offer residential and small business customers a portfolio of green power options that required inclusion of third party suppliers, and significant new renewable energy content. These choices, along with other rate options, served as an alternative to direct access for residential and small commercial customers (larger commercial and industrial customers served by IOUs were given direct access effective October 2001).

To implement the program, the PUC established a portfolio advisory committee (PAC) composed of a range of stakeholders. The PAC made recommendations to the PUC to put structure in place for implementing the program (most, but not all of which were implemented), including recommending a range of specific products. The PAC decided that in each IOU's territory, three renewable options would be offered, one by the IOU and two supplied and marketed by a third party.

The two utilities issued a competitive solicitation conforming with the PUC's rules to select the third party, with selection criteria that included price, proven experience, financial wherewithal to sign long-term contracts, and marketing capabilities. Though the solicitations were independent, both utilities selected Green Mountain Energy (GME) as their third party marketer. The program began signing up customers as of March 1, 2002.

The three offerings include:

A **Fixed Block** product consisting of 100% new wind energy offered in blocks of 100 kWh per month, supplied and marketed by the utility. In the case of Pacific Power, this offer corresponds to the "Blue Sky" program ($2.95/month for 100 kWh) that predated the other legislatively-required options (offered since 2000); PGE's Clean Wind program, also offered since 2000, charges $3.50 per 100 kWh.

A **Renewable Usage**, or blend product, representing 100% of a customer's usage. This is offered by Green Mountain Energy, who supplies RECs and the marketing for the product. It consists of 85% geothermal and 15% new wind energy.

A **Habitat** product, also offered by Green Mountain Energy, is the same as the Renewable Usage product, but also includes a donation for Salmon habitat restoration (modeled after a predecessor program, *Salmon Friendly Power*, originally offered by PGE).

The program is closed: no other competitors or offerings are envisioned to have access to the utility bill (although RECs products offered by others continue to be available in the region).

The duration of GME's contract, however, is only 22 months, through the end of 2003. The PAC is required to report back to the PUC on the program success and make additional recommendations for a solicitation for a subsequent term. The initial program appears to have been shortsighted in not addressing adequately what happened at the end of the initial term to GME or its customers, and the implications on bringing new generation on-line with such a short-term program. The next round of solicitations for 2004 and 2005 are expected to include additional terms and conditions to better address the issues of term, duration, and creating a more stable environment to support long-term green power market growth and financing of new renewables.

In this program, the DISCOs view the third party similar to an outsourced contractor for an offering. The DISCOs serve as collaborative marketers, offering "storefront marketing", with their regulated products "on the shelf" alongside those of the third-party supplier GME. This is described as akin to a supermarket in which name brands are offered alongside the store brand. The IOUs is required to market all three options equally, and the utility and GME have voluntarily decided to undertake collaborative retail marketing where possible. All three programs are featured on the web sites of each IOU[33], and are the subject of utility press releases. PGE announced recently that it is sending out mailings to every residential and small business customer beginning in late October 2002 and extending through the end of the year. Pacific Power announced a new educational campaign with customized enrollment forms, with mailings to begin in November.[34]

The Niagara Mohawk Program

The Niagara Mohawk program came about as a result of pressure by renewable energy advocates during the settlement discussions over approval of a merger between National Grid U.S.A and Niagara Mohawk Power Company (NiMo). It is seen as a transitional program in a direct access market that so far has failed to provide green power alternatives to customers (or for that matter, much competition for smaller customers). As a result of a Joint Proposal by a number of parties, the NiMo agreed to institute a Renewable Energy Marketing and Billing Program to facilitate the sale of renewable energy in its territory.

As of September 2002, competitive "Green ESCOs" that register for the program may offer to Niagara Mohawk's generation service customers green power offerings under their own brands that are based on either (a) 100 or 200 kWh per month blocks of energy consumption, (b) percentages of energy consumption (discreet alternatives include 25%, 50% or 75% of consumption), or (c) the customer's total energy consumption. The NiMo offers no renewable options under its own brand. Billing is performed through NiMo's billing system, with the renewable energy premium separately identified. The Green ESCO arranges service by streaming attributes from renewable generators located within New York to the NiMo for their inclusion on mandated environmental disclosure labels via conversion transactions[35] allowed under the environmental disclosure program. The program is not available to customers that have switched suppliers. The program is open to any registered Green ESCO, and ESCOs can join the program at any time. Offerings are available to both residential and commercial customers.

The program was launched in September 2002 and three Green ESCOs have registered: Community Energy, Green Mountain Energy, and Sterling Planet. Their offerings to residential and commercial customers, respectively, were included in bill-stuffer ballots distributed in a single mailing to all customers over a single bill cycle. The types of offerings, summarized on the ballots shown below in Figures 1 and 2 (Community Energy added a 100% wind option after the ballot was distributed), were selected based on each ESCO's efforts to make their offering appealing and differentiate it relative to competitors' offerings, subject to the menu of options dictated by billing system limitations.

Figure1: September 2002 Residential Ballot

NIAGARA MOHAWK RENEWABLE ENERGY ENROLLMENT CARD

Yes, sign me up to receive renewable energy service from the supplier I have designated below. I am aware that (1) by mailing back this completed card I will have a renewable energy surcharge added to my monthly Niagara Mohawk bill; and (2) Niagara Mohawk will remain my electricity supplier and provide my customer service and emergency response.

Niagara Mohawk Account Number (from your bill)________________________________

Account holder Name ________________________________

Address ________________________ Daytime Phone (______)____________

City________________________ State________ Zip Code__________

Check one supplier below and note option if any.

___ Community Energy 50% Wind/50% Hydro; adds 1.3 cents/kWh on all usage.

___ Green Mountain Energy 85% Hydro/15% Wind; adds 1.5 cents/kWh on all usage.

___ Sterling Planet 30% Wind/20% Hydro/50% Biomass. Select one option:

- ❑ Option 1 – Adds 1.5 cents/kWh on 50% of usage.
- ❑ Option 2 – Adds 1.5 cents/kWh on 75% of usage.
- ❑ Option 3 – Adds 1.5 cents/kWh on 100% of usage.

Niagara Mohawk
A **National Grid** Company

Figure 2: September 2002 Commercial Ballot

NIAGARA MOHAWK RENEWABLE ENERGY ENROLLMENT CARD

Yes, sign me up to receive renewable energy service from the supplier I have designated below. I am aware that (1) by mailing back this completed card I will have a renewable energy surcharge added to my monthly Niagara Mohawk bill; and (2) Niagara Mohawk will remain my electricity supplier and provide my customer service and emergency response.

Niagara Mohawk Account Number (from your bill)________________________________

Accountholder Name ________________________________

Address ________________________ Daytime Phone (______)____________

City ________________________ State__________ Zip Code____________

Check one supplier below and note option if any.

___ Community Energy 100% Wind. Select one option:

- ❑ Option 1 – Add _____ blocks per month at $2.00 per block (5 block minimum)
- ❑ Option 2 – Adds 2.0 cents/kWh on all usage

___ Green Mountain Energy 85% Hydro/15% Wind; adds 1.5 cents/kWh on all usage

___ Sterling Planet 30% Wind/20% Hydro/50% Biomass. Select one option:

- ❑ Option 1 – Adds 1.4 cents/kWh on 50% of usage
- ❑ Option 2 – Adds 1.4 cents/kWh on 75% of usage
- ❑ Option 3 – Adds 1.4 cents/kWh on 100% of usage
- ❑ Option 4 – Adds 1.4 cents/kWh on _____% of usage (Choose your percentage)

Niagara Mohawk
A **National Grid** Company

The primary mode of marketing under the program is the bill stuffer, to be distributed once per year. This explains the program and its voluntary nature. The ballots are returned to an independent firm hired collectively by the registered marketers. In addition to the ballot, the Green ESCOs may market renewable energy service to NiMo customers under their own brand, while referring to the NiMo's role as a distribution company and generation provider for consumer education purposes. The NiMo and the Green ESCOs undertake a limited degree of customer education on the program (consisting mostly of an annual bill stuffer). The Green ESCO will mail quarterly environmental disclosure labels directly to customers.

Unlike the Oregon program, the utility is not providing other marketing support, such as events or other media. Under the settlement, NiMo is only required to do one bill stuffer per year, and NiMo is only doing the minimum required of it to support the program. While additional marketers can join at any time, there is little incentive to join until the next bill stuffer ballot is being prepared.

The program is provisionally established for a term matching the term of the merger Rate Plan (there is significant uncertainty with respect to the actual duration that can be relied upon, or what would happen at the end of the program), as its purpose is to spur the development of renewable generation resources and the sale of renewable energy in NiMo's territory, and is intended at this juncture to be an evolutionary step to a fully competitive direct access market for bundled/delivered generation service. The PSC Staff will monitor the effect of the program on the development of a competitive market and may make recommendations on its continuation or dissolution.

Program Comparison: Structure and Results to Date

A comparative summary of the structure of two programs is found on the table below:

	Oregon	Niagara Mohawk
Genesis of program	Required under restructuring legislation	Merger settlement concession
Suppliers (open/closed)	Limited to DISCO/1 supplier selected through RFP	Open to any registered "Green ESCO"
Customer eligibility	Residential & small commercial not offered direct access	All customers of NiMo generation service
# of competitors and offers	Two suppliers in each service territory Three discrete offers (block, blend, and blend + salmon habitat)	Unlimited in principle. Currently three suppliers offering a total of 5 product choices to residential customers and 7 options for commercial customers
Role of DISCO	Distribution company and generation service provider; Competing green power supplier; Collaborative marketing for all; Billing agent (engaged participant)	Distribution company and generation service provider; Limited marketing for all; Billing agent (reluctant marketing channel, doing the minimum)

	Oregon	Niagara Mohawk
Marketing	Collaborative, "storefront" marketing of utility and 3rd party offerings on equal footing by DISCO and by 3rd party	DISCO as marketing channel through equal treatment of competitive offerings on bill stuffer ballots; plus individual efforts of Green ESCOs
Types of offerings, limitations	3 offers defined in legislation	Discrete range of offerings: 2 sizes of "blocks"; discrete percentages of usage; total consumption
Enrollments	Processed by DISCO	Processed by Green ESCOs
In place since…	March 2002	September 2002
Duration	22 months years (through 12/31/03)	Unclear what happens after duration of Merger Rate Settlement (~3 years?)

While neither program has been in place for long, early results on market penetration are very encouraging. These results are summarized in the table below:

Territory	Number of green power customers	Total eligible customers	Market penetration to date
Pacific Power	3292 as of 12/31/01 11,922 as of 10/24/02[36] (~98% residential)	415,729 residential[37]	~ 2.8% of residential
Portland General Electric	4917 as of 12/31/01 16,795 as of 10/24/02[38] (~98% residential)	637,331 residential[39]	~ 2.6% of residential
Niagara Mohawk	5682 ballots returned as of 12/20/02[40]	1.5 million total 1.4 million residential	~0.4% of residential

In Oregon, the breakdown among products is greater than 50% signing up for the "usage" product, greater than 25% for the "habitat, and less than 20% for the utilities' "block" offerings[41]. The NiMo ballot return figures do not include those customers that contacted Green ESCOs directly. This figure breaks down as follows: Community Energy, 2771; Green Mountain Energy: 245; Sterling Planet: 1155; Multiple suppliers checked: 514; None checked: 765. The presence of the last two categories indicates some degree of confusion during the initial ballot circulation; nonetheless, suppliers sending follow-ups to customers in the last two categories were able to sign up a substantial proportion of the customers in the "none" and "multiple" categories.

Analysis of Competitive Green Pricing Program Experience

Based on an assessment of the available experience, we can draw several conclusions: First, the offerings in NiMO's competitive green pricing program, although otherwise identical to a "tag" offering (i.e. effectuated through tags), appear indistinguishable from a traditional "bundled/delivered" green power product from the customer perception, because it is channeled through the utility bill and from local sources. It is not described as a tag product; rather, it is explained as simply as possible: "you are switching your supply of energy". In fact, when Green-e was asked to certify offerings under this program, they applied their bundled certification standard rather than their tradable renewable certificate standard.

From the marketer perception, these programs have significant advantages over independent RECs offerings, primarily because of the added credibility that comes with being associated with a utility program. In a sense, because it comes through the utility bill, the customer is faced with the option to select a different product/service, rather than being asked to send money to some third party and receiving nothing tangible in return – an act that is similar to request for a charitable contribution from an unfamiliar charity, made far less appealing when made by a for-profit company.

These programs also have significant advantages over delivered/bundled direct access offerings because (a) they can be effectuated with RECs, a far lower cost and lower risk way of conducting business for the green power supplier than arranging for bundled delivered competitive generation supply, and (b) having the utility involved overcomes the fear of switching suppliers that acts as a significant barrier to green choice (or any competitive choice, for that matter).

In comparing the Oregon and NiMo approaches for potential applicability in California, a representative of Community Energy opined that, if well run, the NiMo approach is superior because (i) it offers customers more choices, (ii) it doesn't block market entry (as in Oregon, where competition is limited to a single third party); (iii) it allows for regional diversity as well as product evolution; and (iv) with more marketers, if one folds, more options are available.

However, Community Energy also observed that some specifics of the NiMo approach need not be replicated in California. First, the success of the program is a function of how willing, or how required, the DISCO is to do more than the minimum (e.g. allowing the green options to be on the bill). A more positively engaged DISCO (as is the case in Oregon) would make for better penetration, an opinion echoed by Green Mountain Energy. In addition—the fact that the customer must stay with NiMo generation service to participate prevents customers from participating while simultaneously maintaining the freedom to take the lowest-priced commodity generation offering.

A representative of Green Mountain Energy had a different perspective, finding that the higher level of engagement of the utility in the Oregon program as the primary determinant of that program's relatively greater success. They find that having the utilities do the little things that continually increase awareness – spending their own money on marketing, sending direct mail on their letterhead—will be far more important than offering a greater variety of choices. They also believe that when the program is seen by the utility as more of an outsourced function than supporting competitors, it is easier to get them to understand the degree to which they benefit from demonstrable increases in customer satisfaction. From that perspective, GME, the only common participant to both programs, expects the program results to diverge as a result of the different level of engagement by the utilities: active and enthusiastic support in Oregon, compared to disinterest in NiMo.

Two metrics to consider in comparing a competitive green pricing approach with green marketing in direct access markets, or with RECs in competitive or regulated markets, include penetration rates and customer acquisition costs. With only a few months of experience in a limited sample size, penetration statistics are certainly not conclusive. Nonetheless, the early performance of these programs compares favorably with that of other existing and past programs. For example, even at the height of California's competitive retail market, less than 2% of residential customers were being served by a green power product.[42] Similarly, in Pennsylvania, which is widely considered to be one of the most active competitive markets in the U.S., residential green power customer participation rates have failed to exceed 2%.[43]

While some of the more-than-100 regulated green pricing programs throughout the country have fared better than the competitive green power markets in California and Pennsylvania, NREL's most recent list of the "top ten" green pricing programs ranked by customer participation rates shows that the 10th best program – SMUD's Greenergy – has only achieved a 3.0% participation rate, despite having been in place since 1997.[44] Similarly, an October 2002 report on 23 green pricing programs in the Pacific Northwest shows that only 4 of these programs have exceeded a 2.8% residential participation rate (i.e., that achieved by Pacificorp and PGE since March 2002).[45] Two of these programs have been around since early 1998; the other two since early 1999.

In 2001, the PGE green pricing program was considered by the Federal government to be among the top 10 nationally; since adding multiple competing options, program signups have more than tripled in just none months for both Oregon programs. Blair Swezey of the National Renewable Energy Labs considers this program to be among the best in the nation.[46]

Customer acquisition cost data is closely held as proprietary, so little numerical data is available to support the expectation that this type of program can reach these penetrations at comparatively attractive cost. Nonetheless, the fact that RECs marketers report a preference for access to the utility bill, and that penetration rates exceed those of the best direct access green power markets, suggests that acquisition costs are indeed lower for this type of program. One expected result of lower customer acquisition costs is lower product prices, since the product price must recover acquisition-related costs amortized over the expected duration of the supplier-customer relationship.

The experience of Community Energy supports the conclusion that a competitive green pricing program may be particularly effective. Community Energy has experience in marketing RECs offerings elsewhere, including in a neighboring utility marketing the same generation to similar customer classes in partnership with the local utility (New York State Electric and Gas, NYSEG), in a circumstances where they do not have access to the utility bill. They report that their comparative results so far suggest that, all else being equal, their NiMo offering to residential customers is about twice as successful and more cost-effective than the neighboring NYSEG effort, and that the NYSEG offering to residential customers would likely be far more successful if it were allowed access to the utility bill[47]. They report that they are experiencing similar customer acquisition cost in either program, but anticipate that the costs that result from the utility-based program in NiMo territory, or their exclusive partnership with the DISCO in NYSEG territory, are so superior to the penetration and customer acquisition costs anticipated under a completely independent RECs offering that they have foregone offering such a product to residential customers.

In summary, the limited experience suggests that the market penetration will be far superior to independent RECs offerings, and customer acquisition costs will be lower than both RECs and competitive bundled product offerings. We hypothesize that this is due in large part to the added credibility gained by marketing in association with utility-supported program with regulator support (relative to RECs); the ability to make a switch without switching supplier, and the ability to use bill stuffers and ballots, which can be supplemented by green ESCO marketing.

In California's particular situation, this approach holds greater promise than a green-tag-only market for building upon the green market supported by the Customer Credit program under direct access. It can provide a mechanism for the demand that has already been tapped to be nurtured (rather than losing the direct access customers that have already been invested in over time as marketers continue to abandon a market with no hope of growth), and either serve as a smooth transition to the possible future reopening of direct access, or as a substitute means for effectively developing a green power market in the absence of direct access.

Role for CEC's Customer Credit

Neither the Oregon nor the NiMo program have been directly subsidized (although in New York, Community Energy has won a marketing grant from NYSERDA that has supported their efforts to date, and Green Mountain Energy has reportedly just been awarded a similar grant to support their future marketing efforts). For California, the question remains how the Customer Credit account might be applied to such a program.

Key design questions for program include:

How to implement the program?

Does it require legislation? Would utilities voluntarily support such a program? How to get more than the minimum level of participation and support from the utilities?

The role of the utility?

Billing agent? Competitor? Processing enrollments? "storefront market" including their own product?)

The process for selecting green marketers?

Competitive RFP up front, or program open to all qualified registrants?

Key design questions for Customer Credit funding include:

Who to fund?

Options include (a) funding all purchases from registered green markters offering eligible products (similar to the past Customer Credit rebate), (b) funding certain marketers (akin to NYSERDA's green marketing pay-for-performance grant approach), or (c) funding joint marketing efforts and enrollment and billing system infrastructure rather than marketers or customer rebates.

How to fund?

Options include (a) a per kWh or per customer incentive or rebate, akin to the past Customer Credit program in California or the current Rhode Island small customer incentive, respectively, (b) as marketing grants, or (c) payments for joint marketing efforts or infrastructure.

How much to fund?

There would need to be minimum product requirements to assure credible results and equitable and credible treatment of products of different quality. GME suggested that the best usage of funds may be to support the cost of increasing and maintaining customer awareness, such as a specific and regular (bi-annual?) mailings on DISCO letterhead to customers to describe the program offerings and give them a chance to sign up; and supporting the cost of enrollment processing so that these costs need not be inefficiently duplicated by each party.

How much to fund?

Unlike the previous Customer Credit program, in which substantial rebates were necessary to encourage switching, it would only be necessary to partially support the green premium. The effect of any ¢/kWh credit would be to lower the price or improve the product, which would indirectly improve penetration; support for awareness and signups, as suggested in the paragraph above, would reduce the risk to marketers while more directly improving penetration.

The potential impact of customer credits include greater marketer interest; reduced customer acquisition costs; ability to price at a more sustainable rate (lowering risk of needing to amortize customer acquisition costs over uncertain customer life) than in the absence of any support; and as a result, greater penetration/market transformation.

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Endnotes

[1] Originally, what is now the Customer Credit Account, was one of two Subaccounts of a broader Customer-Side Account.
[2] Decline in funds demand could occur if the CEC determines that it will not pay Customer Credit Account funds to those who applied for them in 2002. Because companies contend that they priced their products to include the Customer Credit Account funds in 2002, these customers may be economically unattractive to the ESPs serving them absent such funds and the customers may be returned to utility bundled service.
[3] The New Account will fund supplemental energy payments which will be awarded to generators who sign contracts with load serving entities in compliance with RPS. The supplemental energy payments will cover the above market cost of the renewable energy procured by the LSE.
[4] The demand for funds from the New Account over the long term will depend on RPS program design, electric demand growth, market prices for renewable energy and capacity and market prices for conventional energy and capacity, among other factors.
[5] Section 383.5 (f)(2)(B) of the Public Utilities Code says in pertinent part, "Credits awarded to members of the combined class of customers, other than residential and small commercial customers, may not exceed one thousand dollars ($1,000) per customer per calendar year. In no event may more than 20 percent of the total customer incentive funds be awarded to members of the combined class of customers other than residential and small commercial customers."
[6] The original SB 90 program total funding limit for Customer Credit Subaccount funding was reached in 2001, after which demand for Account fund from large customers ceased. However, since no funds have yet been disbursed under SB 1038, demand for funds may increase from 2002 levels until the large customer demand reaches the total funding limit.
[7] http://www.bayeconfor.org/pdf/CAenergyfuture.pdf
[8] http://www.nopecinfo.org/
[9] "Introduction to Regional Green Power Markets Reports" Presentation to the 7th National Green Power Marketing Conference, Blair Swezey, National Renewable Energy Laboratory, September 30, 2002, http://www.eren.doe.gov/greenpower/gpmc_pres/7gpmc02/swezey02.pdf
[10] "National Green Power Market Update" Presentation to the 2002 Northwest Green Power Forum, Blair Swezey, National Renewable Energy Laboratory, November 19, 2002.
[11] RECs are the renewable energy attributes generated along with power production from a renewable generator which may be sold separately or in combination with the commodity electricity.
[12] http://www.resource-solutions.org
[13] http://www.epa.gov/greenpower
[14] http://www.usgbc.org
[15] Not all of these states and countries use the term REC, though some do. Regardless of the name, the accounting systems function more or less the same.
[16] For more information about the AAIB effort, please see Appendix B.
[17] For a detailed description of the RECs systems in Texas and New England, see Appendix A.
[18] For more information on RPS accounting options, see Grace, R., W. Wiser and B. Abbanet. 2000. "Massachusetts Renewable Portfolio Standard: RPS Accounting & Verification Mechanisms and Policy Coordination Report." Prepared for the Massachusetts Division of Energy Resources; and Rader, N. and S. Hempling. 2001. "The Renewables Portfolio Standard: A Practical Guide." Prepared for the National Association of Regulatory Utility Commissioners.
[19] ISOs typically also use an automated system to track energy flows at the wholesale level for settlement purposes. These systems are conceptually similar to certificate tracking systems in that meter data is electronically transferred to a central database. One key difference between certificate tracking systems and energy tracking systems is that energy tracking systems track the actual flows of energy, both incoming (generation meter) and outgoing (customer meter), whereas certificate tracking systems usually track only incoming flows to determine the number of certificates that are issued. Once certificates are issued, they can be traded and transferred regardless of the actual energy flow. Instead of tracking outgoing flows by meter use, certificate systems typically retire certificates when they are used to meet customer load, to meet a regulatory requirement such as an RPS, or are exported out of the

system. In this way certificate systems are able to track all certificates generated and "used" to ensure that no one certificate is "used" more than once (double-counting). Typically, a certificate is "used" when it is noted on a disclosure label or used to meet retail load, used for a regulatory purpose, such as an RPS, exported out of the system, or otherwise retired (e.g. if it expires per regulatory or legislative rules)

[20] To completely assure that all registered generators are prevented from double-counting, registries of certificates must coordinate their retirement data. The effort to establish the North American Association of Issuing Bodies would provide such coordination between the TX, New England and other systems.

[21] Contract path systems also suffer from a lack of clear, simple, unambiguous and fair methods of dealing with spot market or undifferentiated system power transactions.

[22] For a detail description of the Oregon and New York programs, see Appendix C.

[23] In order to prevent double counting of the value of the attributes underlying a REC, certifying bodies often allow a REC to be used in energy markets OR converted to pollutions offsets but not for both purposes unless explicitly allowed in the law or rules governing the programs.

[24] This section is based on Wiser, R. and O. Langniss. 2001. "The Renewables Portfolio Standard in Texas: An Early Assessment." LBNL-49107. Berkeley, Calif.: Lawrence Berkeley National Laboratory.

[25] § 39.904 of the Public Utility Regulatory Act (PURA).

[26] PUC Substantive Rules §25.173 Related to Goal for Renewable Energy.

[27] Based on an assumed average capacity factor of 35%. Assuming an average annual growth in demand of 3% this translates to a renewable energy share of 2.2% by 2009.

[28] New England Power Pool Generation Information System Operating Rules.

[29] The incremental cost of establishing a framework that serves the needs of the hemisphere is very low. Both Canada and Mexico have already indicated their interest in participating sometime in the near future.

[30] The AAIB Stakeholders include existing and emerging Issuing Bodies, regulators and market participants.

[31] However, each Issuing Body (TRC tracking system) can and probably will go beyond the minimum standards to include options and services tailored to the needs of the regulators and participants in their region.

[32] When sourced from local renewables.

[33] See: Pacific Power: http://www.pacificpower.net/Navigation/Navigation1845.html
Portland General Electric: http://www.portlandgeneral.com/business/products/power_options/fixed.asp

[34] Pacificorp Press Release: "Oregonians make local renewable energy program one of fastest growing in the country" October 29, 2002

[35] Through a conversion transaction, generation attributes associated with energy sold by generators into the spot market may be transferred to an ESCO purchasing an equivalent quantity of energy from the spot market during a calendar quarter. Such spot market purchases may then take on the generator's characteristics for disclosure purposes.

[36] Source: Pacificorp Press Release: "Oregonians make local renewable energy program one of fastest growing in the country" October 29, 2002.

[37] Source: EIA summary for 2000.

[38] Source: Pacificorp Press Release: "Oregonians make local renewable energy program one of fastest growing in the country" October 29, 2002.

[39] Source: EIA summary for 2000.

[40] Source: Brent Beerley, Community Energy, figures provided to all participating Green ESCOs.

[41] Source: John Savage, Green Mountain Energy.

[42] Wiser et al. 2001. "Forecasting the Growth of Green Power Markets in the United States." http://eetd.lbl.gov/ea/EMS/reports/48611.pdf

[43] Ibid.

[44] http://www.eren.doe.gov/greenpower/topten.shtml

[45] Harris, Ned. 2002. "Power Choices III: A Survey of Retail Green Power Programs in the Pacific Northwest and Beyond." Renewables Northwest Project, August 2002. http://www.rnp.org/htmls/Powerful%20Choices%203_web.pdf

[46] Pacificorp Press Release: "Oregonians make local renewable energy program one of fastest growing in the country" October 29, 2002.

[47] For larger commercial, industrial or institutional customers, the marketing approach is entirely different, and given the ability to market *with* utility representatives in NYSEG territory, their NYSEG experience with larger customers has been superior to the NiMo offering where they have no such partnership.